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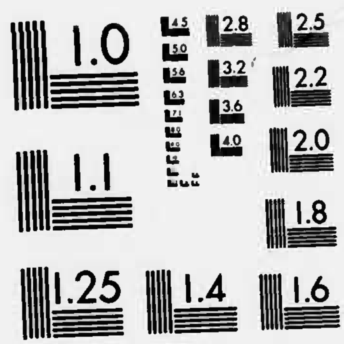

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USAF OEHL REPORT

83-064EA098MEE

FOR HEALTH & ENVIRONMENT

DEVELOPMENT OF A PERMITTING STRATEGY FOR A COAL-FIRED HEATING PLANT

K.I. SAWYER AFB MI 49843

DECEMBER 1982

USAF Occupational and Environmental Health Laboratory
Aerospace Medical Division (AFSC)
Brooks Air Force Base, Texas 78235

NOTICES

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This report develops air pollution design criteria and a corresponding permitting strategy for a candidate coal-fired heating plant. The optimum strategy and fallback strategies are supported by the appropriate calculations and air quality analyses.

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REPORT NO. 83-064EA098MEE

USAF OCCUPATIONAL AND ENVIRONMENTAL

HEALTH LABORATORY

Brooks AFB, Texas 78235

Development of a Permitting Strategy

For a Coal-Fired Heating Plant

K.I. Sawyer AFB MI 49843

December 1982

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PREFACE

In September 1982, the USAF Occupational and Environmental Health Laboratory (USAF OEHL) and HQ SAC Civil Engineering Environmental Planning (DEVQ) contracted Engineering-Science to develop a permitting strategy for a coal-fired heating plant. Engineering-Science performed this permitting strategy study under Contract No. F33615-80-D-4001, Order No. 28. The primary project monitor for HQ SAC/DEVQ was Captain Laddie Mumper. The contract project monitor for the USAF OEHL was Captain Robart Bauer.

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CHAPTER 1

INTRODUCTION

A central heating plant at the KI Sawyer Air Force Base supplies high temperature hot water to nearly all buildings at the base. The existing plant has three oil-fired and two coal-fired boilers. It is proposed to remove the existing three oil-fired boilers and to build two new coal-fired boilers.

The existing plant consists of five boilers. Boilers #1, 3 and 4 are fired with #6 fuel oil and boilers #5 and 6 are fired with coal. Output capacities of boilers #1 and 3 are 31.2 million Btu per hour each. The other three boilers are rated at 30 million Btu per hour output each. The total capacity of the existing plant is, thus, 152.4 million Btu per hour output.

Capacities of the proposed two new boilers are 60 million Btu per hour output each. With the removal of the existing oil-fired boilers and construction of the new boilers, the total capacity of the plant after these modifications will be 180 million Btu per hour.

According to the United States Environmental Protection Agency (EPA), the existing plant is considered a major stationary source because SO_2 emissions exceed 250 tons per year. It is likely that the proposed changes will constitute a major modification and as such will be subject to Prevention of Significant Deterioration (PSD) regulations. This document presents the regulatory requirements and looks at the various options which could be considered for permitting the proposed modifications.

CLEAN AIR ACT REQUIREMENTS

In 1970, the U.S. Congress passed the Clean Air Act (CAA) and established procedures for developing National Ambient Air Quality Standards (NAAQS) for protection of human health and welfare. The CAA furthermore gave the States the option of prescribing more stringent standards if desired. The NAAQS were published by EPA in 1971 and became effective at that time. Subsequently, the Michigan Air Pollution Control Commission (APCC) adopted the national standards as the State standards as part of their state implementation plan (SIP) to attain the federal standards. Table 1.1 summarizes the NAAQS. Although Congress did not include specific provisions in the CAA of 1970, it clearly did not intend to permit a deterioration of the atmosphere in those parts of the country where clean air already existed. These clean areas were defined as those areas which were generally well below the air quality standards.

TABLE 1.1

NATIONAL AND MICHIGAN AMBIENT AIR QUALITY STANDARDS ($\mu g/m^3$)

Pollutant	Averaging Time[a]	Standard[b]	
		Primary	Secondary
Particulate Matter	Annual (Geometric Mean)	75	---[c]
	24-Hour	260	150
Sulfur Dioxide	Annual (Arithmetic Mean)	80	---
	24-Hour	365	---
	3-Hour	---	1,300
Carbon Monoxide	8-Hour	10,000	---
	1-Hour	40,000	---
Photochemical Oxidants	1-Hour	235	---
Hydrocarbons[d]	3-Hour	160	---
Nitrogen Dioxide	Annual (Arithmetic Mean)	100	---

[a] For averaging times other than annual, the NAAQS is not to be exceeded more than once a year. The oxidant standard uses a statistical technique to determine violations.

[b] The primary NAAQS is designed to protect public health; the secondary NAAQS, to protect public welfare.

[c] A guideline of 60 $\mu g/m^3$ is used to test the adequacy of State Implementation Plans (SIPs) in meeting the secondary standard.

[d] The hydrocarbon standard is to be used as a guide in devising SIPs to achieve oxidant standards.

The Clean Air Act Amendments of 1977 established firm ceilings and increments which were not to be exceeded in these clean air areas. Table 1.2 summarizes the maximum allowable increases for different areas of the country. Depending upon the existing air quality levels, different geographical areas of the country were divided into three classes. Class I areas are the cleanest areas and were so designated as environmentally sensitive areas. In these areas, the Congress mandated that there would not be a significant deterioration of the existing air quality. The intent of the Congress is seen in Table 1.2. Very stringent limits were set for Class I areas. Other areas of the country were designated as Class II areas. These areas are those which are below the standards and consist of largely populated and industrial centers of the United States. There were no Class III areas, i.e., areas where industrial growth is maximized such that the ceilings become the NAAQS. Any major stationary source (new or modified) which is located within 10 km of a PSD Class I area must also show that the impact of a given pollutant is less than 1 microgram per cubic meter, 24-hour average in order to be exempt from PSD review for that pollutant.

The KI Sawyer AFB is in Air Quality Control Region (AQCR) #126 called "Upper Michigan AQCR". This AQCR has been designated as a non-attainment area for ozone. The area around the base is an attainment area for all other pollutants. Since PSD increments have been set only for TSP and SO_2, the Base falls in a PSD Class II area. The nearest Class I area is Seney National Wildness Area (NWA) approximately 86 kilometers to the east of the Base. Another PSD Class I area in Michigan is Isle Royale NWA which is approximately 240 kilometers northwest of the Base.

In addition to these national standards, maximum PSD ceilings and increments, Congress also established new source performance standards (NSPS) which restrict the amount of emissions that can be discharged from various major source categories. These standards apply to new major sources. The new boilers proposed for the plant do not come under the NSPS since their heat input is below the 250 mmBtu/hour requirement specified in the boiler standard.

EPA'S PSD PERMITTING PROGRAM

EPA's PSD program was established on August 7, 1977, under the CAA Amendments. Subsequently, on June 19, 1978, EPA published the requirements for obtaining PSD permits in the Federal Register. These June 1978 regulations describe the specific types of monitoring and modeling analyses which would have to be conducted for major sources. Furthermore, the notice defined the types of review and the review period which EPA will use in analyzing permit applications. On October 10, 1978, a suit was brought by Alabama Power, et al. concerning the regulations published in June by EPA. After lengthy debate, several decisions were rendered by the court. The court's decisions differed from what EPA had promulgated in its June 19 regulations. Definitions on major source, types of pollutants to be analyzed, ambient monitoring, modeling, and other issues were objected to by Alabama Power, et al. The court, in 1979, remanded to EPA the task of revising its PSD regulations. On September 5, 1979, EPA published proposed revisions to its PSD permitting regulations. The

TABLE 1.2

MAXIMUM ALLOWABLE INCREASES FOR PSD AREAS[a]

Pollutant	Averaging Time	Increment ($\mu g/m^3$)
	CLASS I AREAS	
Particulate Matter	Annual (Geometric Mean)	5
	24-Hour (Maximum)	10
Sulfur Dioxide	Annual (Arithmetic Mean)	2
	24-Hour (Maximum)	5
	3-Hour (Maximum)	25
	CLASS II AREAS	
Particulate Matter	Annual (Geometric Mean)	19
	24-Hour (Maximum)	37
Sulfur Dioxide	Annual (Arithmetic Mean)	20
	24-Hour (Maximum)	91
	3-Hour (Maximum)	512

[a] State of Michigan allows only 80% consumption of the maximum allowable PSD increments.

final court decision was rendered on December 14, 1979. On that date, the court reaffirmed its earlier decisions on the validity of the provisions at issue in Alabama Power.

The final PSD regulations were promulgated by EPA on August 7, 1980. There were many changes in this notice from the earlier guidance on permitting. These new permitting requirements have been incorporated into this permit application.

STATE PERMIT REQUIREMENTS

The prime responsibility for achieving the air quality standards rests with each state. The CAA Amendments of 1977 establish specific requirements for allowing new source growth to occur in various areas. The states had to adopt these regulations, which affect industrial growth, as part of their State Implementation Plan (SIP) revisions submitted to EPA in 1979. Congress intends that the PSD program be taken over by the states. Under this provision, the Michigan APCC has been delegated the authority for complete control of issuing permits to sources within its jurisdiction.

The State PSD permit program is similar to the one promulgated by USEPA with one exception. Whereas USEPA regulations allow the consumption of maximum allowable PSD increments, the State of Michigan allows only 80% of the maximum PSD increments to be consumed.

In addition state permits to construct and to operate must also be obtained. Normal processing time for a permit is 60 days after submission of a complete application. Within 30 days of the completion of proposed constructions, the Base will have to apply for a permit to operate. The permit to operate continues to be in effect as long as the equipment operates in accordance with the permit conditions. There is no fee charged for a permit to construct or to operate; however, there is an annual surveillance fee which is based on the amount and type of pollutants being emitted and the difficulty of investigation of the source. The minimum fee is $25 per year. The annual surveillance fee will be determined by the Michigan Department of Natural Resources. Copies of regulations governing such fees are given in Appendix A.

Specific Michigan APCC regulations applicable to the coal-fired boilers are described below. These regulations only cover the air pollution aspect of the permit. In addition a permit from the Michigan Water Resources Commission must be obtained. This permit is required 180 days prior to commencement of operation. For a complete determination of any other permits required, the Michigan Department of Natural Resources must be contacted.

Applicable State Air Pollution Regulations

Specific Michigan APCC regulations which would apply to the new coal and/or wood fired boilers are rules 220, 331, 370 and 402. Copies of these regulations are enclosed as Appendix A.

Rule 220 specifies several requirements for sources of Volatile Organic Compounds (VOC) in an ozone nonattainment area. One requirement under this rule is to provide for an emission offset (reduction) of the total hourly and annual VOC emissions from existing sources equal to 110% of the allowed emissions from the proposed equipment. However, sources which will result in a net increase in VOC emissions less than 50 tons per year, 1000 pounds per day and 100 pounds per hour are exempted from the requirement of this rule. VOC emissions from burning coal are usually low and it is believed that the proposed new boilers would be exempted from this rule.

Rule 331 specifies limits on the emissions of particulate matter from the fuel burning equipment. For new coal-fired boilers the limit is 0.10 pounds per 1000 pounds of exhaust gases at 50% excess air. When burning wood or wood and coal (as long as heat input of wood fuel is 75% or more of the total heat input) the allowable limit is 0.50 lb per 1000 lbs of exhaust gases. For any other combination of wood and coal firing, the allowable emission limit is determined by Michigan APCC on a case by case basis.

Rule 370 covers the disposal of collected air contaminants. Good engineering practices to minimize introduction of these contaminants into the air are generally required. For sources located in Michigan Priority I and II areas, there are specific requirements. Since the KI Sawyer AFB is not located in Priority I or II areas, these specific requirements do not apply. These Priority I and II areas are different from PSD Class I and II areas and should not be confused.

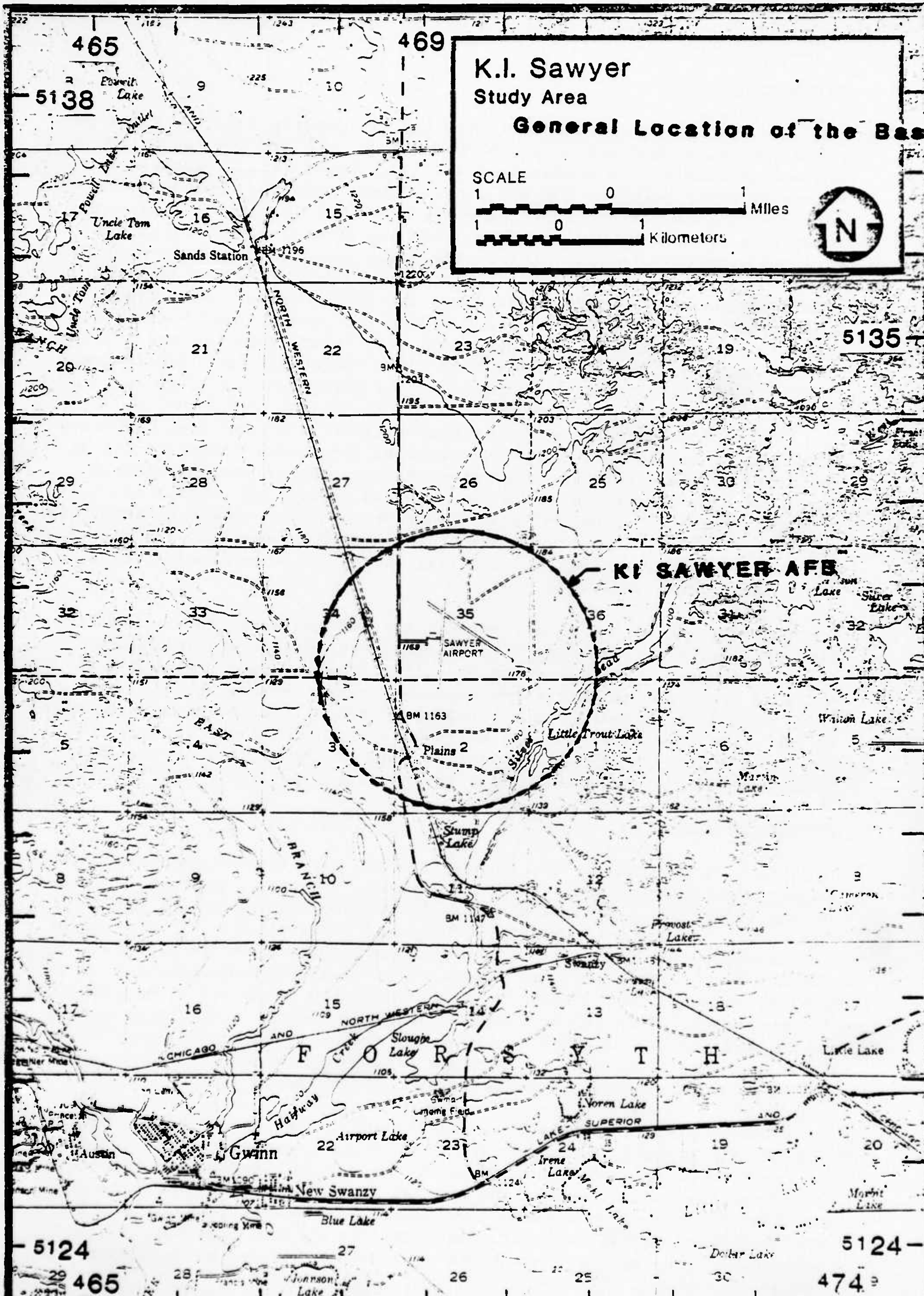
Rule 402 governs the emissions of sulfur dioxide from fuel burning sources other than power plants. This rule sets a limit of 2.4 lb SO_2 per million Btu input. Again sources subject to PSD regulations may be required to meet more stringent SO_2 limits. This regulation does not make a distinction between the type of fuel used and is thus applicable to coal and/or wood firing as well.

There are regulations which cover the control of fugitive emissions but these only apply to sources located in Priority Class I and II areas.

The Michigan application forms for a permit to construct the new boilers are given in Appendix B. The information included refers to the recommended strategy.

AIR POLLUTION SOURCES

The sources of air pollution at the KI Sawyer heating plant are the boilers used to furnish space heat to the buildings. After the proposed modification, the two new boilers and the two existing boilers will be the only sources of emissions at the heating plant. Figure 1.1 shows the general location of the heating plant. The new boilers will be located on the existing property and will be located close to the existing boilers.


K.I. Sawyer
Study Area
General Location of the Base
SCALE
1 0 1 Miles
1 0 1 Kilometers
N
KI SAWYER AFB
SAWYER AIRPORT
Sands Station
Uncle Tom Lake
Powell Lake
NORTH WESTERN
BM 1163
Plains
Little Trout Lake
Stump Lake
Provost Lake
Swanzy
Slough Lake
CHICAGO AND NORTH WESTERN
F O R S Y T H
Halfway Creek
Airport Lake
Voren Lake
LAKE SUPERIOR
Irene Lake
Austin
Gwinn
New Swanzy
Blue Lake
Dollar Lake
Little Lake
Walton Lake
465
469
474
5138
5135
5124

METHODOLOGY

The methodology used to evaluate the air quality impacts of the proposed expansion consists mainly of predicting, through the use of computer dispersion models, the ambient air quality concentrations expected at virtually every point in the x-y plane. These modeling procedures are well established for geographical areas where flat terrain exists. The study area around the base is flat. EPA has several models which are applicable to flat terrain areas. The basic model used in this analysis was a modified version of EPA's single-source model (CRSTER) which allows consideration of spatially distributed multiple sources. This model was used to determine short-term (i.e., 3-hour and 24-hour) and long-term (annual) concentrations. Another model used in the analysis was Industrial Source Complex (ISC) model to predict concentration under downwash conditions in the immediate vicinity of the boilers.

The methodology of completing this analysis also included the establishment of air quality and meteorological data bases. Ambient air data collected by the Air Quality Division, Michigan Department of Natural Resources were used to describe the baseline conditions in this area. Meteorological data used in the analysis were hourly surface observations made at the Sawyer Airport. Upper air data used in the analysis was that obtained for Sault St. Marie. One year (1964) of meteorological data were used in this analysis.

In addition to the model, meteorology and the baseline air quality data, the emissions expected from the proposed new boilers are defined in this document. The emissions of sulfur dioxide are of paramount importance since SO_2 emissions are expected to be the largest component of total pollutant emissions from these sources. All of the data were input to the dispersion model and estimates were made of the air quality impacts. The air quality impacts were evaluated against the ambient air quality standards and PSD increments/ceilings applicable to this area.

REPORT ORGANIZATION

This report follows the format of a PSD permit application to construct two new boilers at the KI Sawyer AFB. Chapter 2 presents a summary of the report and its conclusions. All emission data analyzed are in Chapter 3. Baseline air quality levels and the available PSD increments are addressed in Chapter 4. The meteorological data set is discussed in Chapter 5. And, finally, the impact of the new boiler emissions on air quality is summarized in Chapter 6. In addition there are five appendices to the report. A review of control technology requirements is presented as an appendix to this report. Other appendices include copies of applicable Michigan APCC rules, a Michigan permit application, sample computer runs and a description of the dispersion models used.

This report represents an impartial and technical evaluation of the air quality impacts associated with the proposed expansion. The principal ES investigator was Mr. Glenn T. Reed. He was assisted on the project by Dr. Chandrika Prasad, senior engineer at ES, who directed the modeling and control technology review. Mr. Edward Sabo was responsible for running the dispersion models and calculating the air quality impacts. Overall technical review of the project was provided by Messrs. M. Dean High and Michael E. Lukey.

CHAPTER 2

SUMMARY AND CONCLUSIONS

Heating requirements at KI Sawyer Air Force Base are currently supplied by three oil-fired and two coal-fired boilers. The Air Force intends to replace the oil-fired boilers with two new coal-fired boilers. Such a coal conversion project will require permits from the Michigan Air Pollution Control Commission (APCC). Depending on the magnitude of the air pollution emissions a federal Prevention of Significant Deterioration (PSD) permit may also be required. In this study, ES analyzed several options for permitting the new boilers under PSD and other Michigan APCC regulations.

SUMMARY OF RESULTS

The different emission scenarios which were analyzed can be divided into four groups:

<u>Group A. Claim Emission Credits From All Existing Boilers</u>

The following specific scenarios were analyzed in this group:

1. Burn 100% coal in the new boilers and use the two existing coal-fired boilers as standby. Limit the sulfur content of the coal to 0.80% to avoid PSD review for SO_2. PSD review for NO_x is required.

2. Limit coal usage to 80% of the heat requirement with the remainder supplied by wood. The sulfur content of the coal is 0.98% in order to avoid PSD review for SO_2. PSD review for NO_x is required.

3. Limit coal usage to 60% of the heat requirement with the remainder supplied by wood. The sulfur content of the coal is 1.3% to avoid PSD review for SO_2. PSD review for NO_x is required.

4. Limit coal usage to 45% of the heat requirement with the remainder supplied by wood. The sulfur content of the coal is 1.7% to avoid PSD review for SO_2. PSD review for NO_x is required.

5. Burn 100% wood in the new boilers with the existing coal-fired boilers as standby. NO PSD review for SO_2 is required. PSD review for NO_x is required.

Group B. Claim Emission Credits From Existing Oil Fired Boilers Only

The specific scenarios analyzed under this group are:

6. Limit coal consumption in the new boilers and continue to use the existing coal-fired boilers at the current operating rate. The sulfur content of coal would have to be limited to 0.52% in order to avoid PSD review for SO_2. PSD for NO_x is required.

7. Burn coal and wood in the new boilers and continue to use the existing coal-fired boilers at the current operating rate. Sulfur content of the coal burned in the new boilers would be 0.98%. The heat requirement from the new boilers would be split 73% coal and 27% wood. PSD review for NO_x is required.

8. Limit usage of the new boilers to burn 13,802 tons of coal and burn 13,055 tons of coal (an increase of 63% from 1979 level of operation) in the existing boilers. Sulfur content of the coal is 0.98% in order to avoid PSD review for SO_2. PSD review for NO_x is not required.

Group C. Claim No Credits For Existing Boilers

One Scenario analyzed under this group is as follows:

9. This scenario assumes no limit on the amount of coal usages in the new boilers and no credits for existing boilers will be claimed. If the existing boilers are decommissioned or used as standby, the emissions from these boilers can be banked for use in future expansion.

Under this scenario, PSD review for both SO_2 and NO_x will be required. To avoid PSD review for SO_2 the sulfur content has to be less than 0.5% which is not practical. Sulfur content of the coal could in no case exceed 1.54% because at that sulfur content, all of the PSD increments available will be consumed.

Group D. Consume Part or All of PSD Increments and Consider Other Miscellaneous Plant Configurations

Other scenarios as described in Chapter 6 were considered in order to determine the limitations on the boilers before the NAAQS would be violated or certain percentages of the PSD increment would be consumed. These scenarios were considered in order to establish bounds for the operation of the new boilers and are, in general, unrealistic with respect to actual plant operation. Building of two stacks versus one stack was also evaluated.

CONCLUSIONS

In the analysis, two major requirements under PSD regulations were considered. The air quality impacts of emissions from the new boilers were determined by air quality dispersion modeling. These predicted

impacts were compared with the PSD increments and with the NAAQS. Best available control technology (BACT) was considered although it would not be necessary for all pollutants under all scenarios.

Based upon the results of these analyses, the following conclusions were drawn:

1. Decommissioning of the existing oil-fired boilers will provide some SO_2 emission reduction credits to offset increased emissions from the new boilers. However, these credits are small, and limiting the operating hours or capacity of the new boilers or the sulfur content of the coal would be necessary in order to avoid a PSD review.

2. In order to establish the emissions baseline for determining emission reduction credits, 1979 operations and fuel usage rates would have to be used.

3. If a PSD review is necessary, i.e., the Air Force is unable to accept the limitations required to avoid PSD review, state emission standards would still have to be met. Particulate emissions could be restricted to 0.3 to 0.6 lb/million Btu. The sulfur dioxide limitation might be 1.6 lb/million Btu. A baghouse could be used to meet the particulate limit. The sulfur content of the coal could not exceed 1.0% to meet such a SO_2 restriction.

4. Emissions from the new boilers would not cause a violation of any NAAQS nor would PSD increments be exceeded if sulfur content of coal is 1.54% or lower. The maximum impact from the new boilers (withough any credits for existing boilers as in Scenario IX) operating at full load year-round using the existing coal (0.98% sulfur) would be 29.4% of the annual, 63.7% of the 24-hour, and 23.4% of the 3-hour PSD Class II area increments available. Thus, Michigan's requirement that a single new source cannot consume more than 80% of an increment would be met. The use of 1.54% sulphur coal will consume all the available 24-hour PSD increment before consuming all increments for other averaging periods.

5. In order to preserve maximum flexibility for the Air Force in the choice of coal quality, the emission scenario #9 is best. With this scenario, PSD review would be required for SO_2 and NO_x.

RECOMMENDATIONS

From the several permitting strategies considered in this analysis, it appears that the construction of new boilers will be subject to PSD regulations and a PSD permit application will have to be prepared.

Air quality impact analyses indicate that a 1.54% sulfur coal could be accomodated without violating any PSD increments or exceeding the NAAQS. A 1.54% coal is equivalent to approximately 2.2 lb per million Btu which is less than the state emission limit of 2.4 lb per million Btu. However, it is doubtful if Michigan DNR would accept 1.54% sulfur coal as BACT for SO_2 control. New Source Performance Standards (NSPS) of 1.2 lb per million Btu applicable to larger boilers could be used as a guide for BACT. A 1.2 lb per million Btu emission limit is equivalent to burning 0.85% sulfur coal. For about 15 other coal fired boilers of similar size permitted in the state, the DNR defined BACT as 1.6 lb/MMBtu. Thus, BACT for SO_2 would range from 0.85 to 1.0% sulfur coal. In a recent PSD permit application to Michigan DNR, Engineering-Science has demonstrated use of 1.0% sulfur coal as BACT for boilers similar in size as proposed for the KI Sawyer AFB.

Thus, it is recommended that the Air Force could persue permitting the new boilers to burn 1.0% sulfur coal with no restrictions on the amount of coal usage and no credits claimed for the existing boilers. Burning of wood chips or pellets would result in lower SO_2 emissions and could be accomodated without violating any emission limits or air quality increments which are permitted with 100% coal. Hence, it is suggested that the Air Force try to obtain the permit based on meeting 100% of the load with coal and consider wood burning as a mitigating measure which may or may not be used. This strategy will provide maximum operating flexibility to the Air Force. This strategy is referred to as scenario #9 in this report.

A draft application to the State of Michigan for this recommended option has been prepared and appended to this report.

Based on the analysis completed in this document and the previous experience with coal fired boiler permits in Michigan, we do not feel that it will be difficult to obtain a PSD permit for the Air Force with all of the operating flexibility desired. To secure the necessary permits for the Michigan DNR will take between five to seven months from the time it is initially submitted to the agency.

CHAPTER 3

EMISSIONS INVENTORY

This chapter defines the specific emission rates which were used in evaluating air quality impacts under different emission scenarios. Emissions from the existing boilers are also presented in this Chapter.

EMISSIONS FROM EXISTING BOILERS

Emissions from the existing heating plant are given in Table 3.1. These emissions were computed on the basis of fuel consumption and EPA's approved emission factors. Emission factors were taken from EPA publication AP-42 entitled "Compilation of Air Pollutant Emission Factors, third edition and its supplements 1 through 12" and are reproduced in Table 3.2 for reference purposes.

A major concern when air pollution sources are to be replaced is to establish the actual emissions from the existing sources. Federal PSD regulations specify that the preceding two years are to be used to estabish the emissions baseline unless another emission rate is more representative of normal source operation. Table 3.3 shows the fuel consumption, total heat input, and degree heating days for the past ten years at KI Sawyer AFB. A careful review of this table indicates that fuel usage during the previous two years (1980 and 1981) was abnormally low because the number of degree heating days during these two years was lower than average. The mean number of degree heating days during the past ten years was 9785. The median was 9914. Although fuel usage is not totally dependent upon degree heating days, the requirements of a central heating plant at an Air Force Base must be sufficient to meet the increased demand placed upon the plant during cold winters. Fuel usage during 1979 would appear to be more typical of the plant's recent operations. The number of degree heating days during 1979 was nearer to the 10-year average than 1980/81. The 1979 coal usage is closer to the five year average of 8144 tons. During 1979, the total heat input per degree heating day was 54.5 million Btu/degree heating day. Although this value is the lowest of the past five years, it is close to the ten year average of 53.4 million Btu/degree heating day. However, since a baseline must be established in order to determine the emissions reductions from decommissioning the oil fired boilers, 1979 appears to be the best year to use. Based upon this evaluation, fuel usage during 1979 was selected in order to establish the actual emissions baseline.

TABLE 3.1

EMISSIONS AND STACK PARAMETERS
(Existing Heating Plant)

Item	Boilers #1, 3, & 4	Boilers #5 & 6	Total
Boiler Capacity (MMBtu/hr)	92.4	60.0	152.4
Heat Input[a] (MMBtu/hr)	108.7	70.6	179.3
Maximum Hourly Fuel Consumption			
Coal[b] (ton/hr)	----	2.63	2.63
Oil[c] (gal/hr)	747	----	747
Annual Average Fuel Consumption[d]			
Coal (ton/year)	----	7,419	7,419
Oil (gal/year)	2,445,557	----	2,445,557
Actual Average Emissions[e] (tons/year)			
TSP	18	12	30
SO_2	217	138	355
CO	6	7	13
VOC	1	4	5
NO_x	73	56	129
Stack Parameters[f]			
Height (feet)	82	82	
Diameter (feet)	4.25	4.25	
Temperature (°F)	360	360	
Flow Rate (acfm)	42,150	28,176	

a A boiler efficiency of 85% was assumed.
b On the basis of coal heating value = 13,420 Btu/lb.
c On the basis of oil heating value = 145,510 Btu/gal.
d As obtained from log of fuel consumption for 1979.
e Based on actual fuel consumption.
f Values for each boiler stack. Flow rate is based on maximum design heat input.

TABLE 3.2

EMISSION FACTORS AND FUEL QUALITY
(Existing Plant)

Fuel	Pollutant	Emission Factor[a]	Units
Coal[a]	TSP	79.3	(lb/ton)
	SO_2	37.2	(lb/ton)
	CO	2	(lb/ton)
	VOC	1	(lb/ton)
	NO_x	15	(lb/ton)
Oil[b]	TSP	14.3	(lb/1000 gal)
	SO_2	177.4	(lb/1000 gal)
	CO	5	(lb/1000 gal)
	VOC	1	(lb/1000 gal)
	NO_x	60	(lb/1000 gal)

[a] Average 1980-81 Coal Quality: Ash = 6.1%
Sulfur = 0.98%
Heating Value = 13,420 Btu/lb

[b] Average 1980-81 Oil Quality: Sulfur = 1.13%
Heating Value = 145,510 Btu/gal

TABLE 3.3

SUMMARY OF PAST TEN YEARS OF FUEL USAGE AT KI SAWYER AFB[a]

Year	Oil Consumption (Gallons)	Coal Consumption (Tons)	Total Heat Input (Million Btu)	Degree Heating Days
1981	2,309,032	7,258	530,806	8,914
1980	1,692,899	10,979	540,993	9,436
1979	2,445,557	7,419	554,990	10,187
1978	2,029,235	9,708	552,649	10,030
1977	2,614,682	5,357	522,359	9,252
1976	1,533,528	11,707	520,280	10,290
1975	1,746,105	8,672	486,832[b]	9,509
1974	2,269,760	6,428	502,800[b]	10,005
1973	1,082,572	12,553	494,448[b]	9,312
1972	---	18,637	500,217[b]	10,914

[a] Information provided by DEEV/410th Civil Engineering Squadron, KI Sawyer AFB.

[b] Calculated from fuel use data based on heating values of 13,420 Btu/lb of coal and 145,510 Btu/gal of #6 fuel oil.

For boilers #1, 3 and 4 which are oil-fired, the effect of particulate control devices was considered negligible. These boilers are equipped with mechanical collectors which are considered ineffective in controlling smaller size particulates which are normally emitted from oil burning. The mechanical collectors were installed on these boilers when they were coal-fired. A collection efficiency of 96% for the electrostatic precipitator was assumed in computing TSP emissions from coal-fired boilers #5 and 6.

Fuel quality used in these computations was based on the average for 1980-81 fuel data and is given below:

Coal: ash = 6.1%
sulfur = 0.98%
heating value = 13,420 Btu/lb

Oil: sulfur = 1.13%
heating value = 145,510 Btu/gal

Stack parameters for the exiting plant are also given in Table 3.1. The stack exit gas temperature is not measured but was estimated to be 360°F (the Base estimates vary between 320 to 400°F depending upon heating load).

PROPOSED PLANT CONFIGURATION

Plant records indicate an average maximum load of 74 MMBtu/hour. A peak load of as high as 95 MMBtu/hour has been observed in January 1982. Based on projected heating requirements which include future exapansion and connecting existing individually oil heated facilities to the central heating plant, it is proposed to decommission oil-fired boilers #1, 3 and 4 and to build two new coal-fired boilers of 60 MMBtu/hour capacity each. The total capacity of the modified plant will thus be 180 million Btu/hour.

The design load of the new boilers is 120 million Btu/hr. It has been proposed to operate the new generating units along with the two existing 30 million Btu per hour coal-fired boilers. Under this arrangement, taking off one of the largest 60 million Btu per hour boiler off line, will still allow the peak heating plant load to be carried with the remaining 60 million Btu/hour boiler and the two 30 million Btu per hour units. The new boilers will each have continuous capacity of operating at 110 percent load for two-hour periods. Another opearating scenario will be to operate the two new boilers and have the older boilers (two 30 million Btu per hour capacity) as standby. The advantage of having the older units as standby is that a much higher emission credit can be utilized, which will result in a much higher credit for air quality impacts due to poor dispersion characteristics of the older boilers.

Air Force central heating plants are normally designed to meet 125% of the worst expected heat demand. Using a factor of 1.25, the maximum projected heat input required is estimated to be 694,000 million Btu per year based upon the heat input used in 1979.

Criteria for Selection of Emission Scenarios

A primary concern in defining emission scenarios for the proposed heating plant is to consider applicability of PSD regulations. PSD regulations apply to major sources and major modifications. A source listed in Table 3.4 is considered major if the emission of any criteria pollutant is greater than 100 tons per year. A source not included in one of these categories is also considered major if the emissions of any criteria pollutant exceed 250 tons per year. A modification is considered major if it results in a net increase of any pollutant greater than the de minimus values for that pollutant as given in Table 3.5.

The existing plant is not one of the 28 categories of sources listed in PSD regulations; however, the existing plant is considered major since the actual SO_2 emissions exceed 250 tons per year. Proposed modifications including credits for the existing boilers would be considered major if the net increase of any pollutant exceed the de minimus values for that pollutant. Major pollutants from burning coal would be SO_2 and NO_x and thus SO_2 and NO_x emissions will be the controlling factor in determining whether the proposed modifications will be considered major.

Exceeding the deminimus values will result in the application of PSD regulations. A new or modified source governed by PSD regulations must meet the following requirements.

1. An analysis to show that the Best Available Control Technology will be used.

2. An air quality analysis to demonstrate that (i) the available PSD increments would not be exceeded and (ii) the national ambient air quality standards will be maintained.

Fuel Requirements

Based on an annual design load of 694,000 MMBtu, fuel requirements under several scenarios are shown in Table 3.6. Since the Base has expressed a desire to burn wood or wood pellets in conjunction with coal, several coal-wood combinations were considered as shown in Table 3.6. For purposes of this calculation, a heating value of 8300 Btu/lb was used for wood. Amount of wood required will depend upon the heating value of wood used. Fuel specifications for the Base calls for a heating value of coal to be 14,000 Btu/lb. The coal received during 1980-81 had an average heating value of 13,420 Btu/lb. In order to be on the conservative side, the lower heating value (13,420 Btu/lb) was used in all calculations.

Limiting the sulfur content of coal to avoid BACT for SO_2 for each scenario is also shown in Table 3.6. As will be shown later, all scenarios will be subject to PSD review because of a NO_x emissions increase greater than 40 tpy; however limiting the sulfur content to values, given in Table 3.6 would not require application of Best Available Control Technology for sulfur dioxide.

TABLE 3.4

PSD SOURCE CATEGORIES[a]

---

1. Fossil fuel-fired steam electric plants of more than 250 million Btu/hr heat input
2. Coal cleaning plants (with thermal dryers)
3. Kraft pulp mills
4. Portland cement plants
5. Primary zinc smelters
6. Iron and steel mill plants
7. Primary aluminum ore reduction plants
8. Primary cooper smelters
9. Municipal incinerators capable of charging more than 250 tons of refuse per day
10. Hydrofluoric acid plants
11. Sulfuric acid plants
12. Nitric acid plants
13. Petroleum refineries
14. Lime plants
15. Phosphate rock processing plants
16. Coke oven batteries
17. Sulfur recovery plants
18. Carbon black plants (furnace process)
19. Primary lead smelters
20. Fuel converison plants
21. Sintering plants
22. Secondary metal production plants
23. Chemical process plants
24. Fossil fuel boilers (or combinations thereof) totaling more than 250 million Btu/hr heat input
25. Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels
26. Taconite ore processing plants
27. Glass fiber processing plants
28. Charcoal production plants

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[a] These source categories are listed in both the Clean Air Act and PSD regulations. A source in one of these categories is major if emissions of any criteria pollutant is greater than 100 tons per year. A source not included in one of these categories is major if emissions of any criteria pollutant exceeds 250 tons per year. Criteria pollutants are particulate matter, sulfur dioxide, carbon monoxide, volatile organic compounds, and oxides of nitrogen.

TABLE 3.5

DE MINIMUS EMISSION RATES[a]

Pollutant	Emission Rate (Tons Per Year)
Carbon Monoxide	100
Nitrogen Oxides	40
Sulfur Dioxide	40
Total Suspended Particulates	25
Volatile Organic Compounds	40
Lead	0.6
Asbestos	0.007
Beryllium	0.0004
Mercury	0.1
Vinyl Chloride	1.0
Fluorides	3
Sulfuric Acid Mist	7
Total Reduced Sulfur (inc. H_2S)	10
Reduced Sulfur (inc. H_2S)	10
Hydrogen Sulfide	10

[a] Any new or modified major stationary source which is to be located within ten kilometers of a Class I area must also show that the impact of a given pollutant is less than 1 $\mu g/m^3$, 24-hour average, in order to be exempt from PSD review for that pollutant.

TABLE 3.6

ANNUAL FUEL REQUIREMENT[a]
(New Boilers Only)

Scenario[c]	Description (%)[b] Coal	Wood	Amount of Fuel Required (tons/year) Coal[d]	Wood[e]	Limiting Sulfur Content of Coal to Avoid BACT Requirement for SO_2
I	100	-	25,857	---	0.80
II	80	20	20,686	8,360	0.98
III	60	40	15,514	16,720	1.30
IV	45	55	11,636	22,994	1.70
V	-	100	----	41,808	---
VI	100	---	18,438	---	0.52
VII	73	27	13,460	8,050	0.98
VIII	100	---	13,802	---	0.98
IX	100	---	45,990	---	0.05

a Based on 694,000 MMBtu/year heat input for scenarios I-V and IX, 494,876 for VI and VII and 370,446 for VIII, under Scenarios VI, VII and VIII the remaining heat demand will be met by boilers #5 and 6.
b % refers to % of heat input.
c SO_2 emissions credit for Scenarios I through IV are 355 ton/year, for Scenarios VI through VIII are 217 ton/year and none for Scenario IX.
d Based on coal with 13,420 Btu/lb.
e Based on wood with 8,300 Btu/lb.

EMISSION SCENARIOS

A number of emission scenarios was considered for analysis. These scenarios can be grouped into four general categories.

1. Claim emission credits for all existing boilers. Scenarios I through V fall in this group. These scenarios are based on the assumption that existing oil-fired boilers will be used as standby.

2. Claim credits for oil-fired boilers only. Scenarios VI through VIII falls in this group. Under these scenarios, existing oil fired boilers will be decommissioned but existing coal fired boilers will remain in normal operation.

3. Claim no emission credits. Under this scenario (Scenario IX) the new coal fired boilers will be built without any emission credits from the existing boilers. When oil-fired boilers are decommissioned, available emissions can be banked to be used in future expansion.

4. Consume all or part of the available PSD increments and certain variations from the recommended strategy. Scenarios X through XVI fall into this group.

Detailed descriptions of Scenarios I through IX follows. Scenarios X through XVI are described in Chapter 6.

Scenario I: 100% Coal

This scenario postulates use of 100% coal (25,857 tons/year) in new boilers and having boilers #5 and 6 as standby. Under this scenario, the proposed changes would be considered a major modification due to an increase (65 tons/year) in NO_x emissions which is greater than the de minimus emission rate. The changes would also be considered major modifications due to the SO_2 emissions increase if sulfur content of coal is more than 0.80%. Limiting the sulfur content to 0.80% or less would not require application of BACT for SO_2 control.

Scenario II: Limited Use of Coal with 0.98% Sulfur Content

This scenario was developed on the basis of coal quality (0.98%) currently in use. It was further assumed that boiler #5 and 6 would be standby. Under this scenario, use of 0.98% sulfur coal would not trigger a BACT requirement for SO_2 if the coal usages in the new boilers be limited to 80% (20,686 tpy) and the remaining 20% of the heat requirement is met by burning wood (8,360 tpy) in the new boilers. However, this scenario will be considered a major modification due to the NO_x emissions increase.

Scenario III: Limited Use of Coal With 1.3% Sulfur Content

This scenario is similar to scenario II except that the sulfur content of coal is assumed to be 1.3% which is the current fuel specification. Use of coal limited to 60% (15,514 tpy) would avoid BACT for SO_2. The

modifications would be subject to PSD review due to the increase in NO_x emissions being more than the de minimus level.

Scenario IV: Limited Use of Coal with 1.7% Sulfur Content

This scenario is similar to scenarios II and III but assumes a higher sulfur coal. Use of 1.7% sulfur coal would require a limit on coal usage to 45% (11,636 tpy) in the new boilers. Such limited coal usage would require no BACT for SO_2 but the changes would be considered major modifications due to the NO_x emissions increase.

Scenario V: Use of 100% Wood

Use of 100% wood burning in the new boilers would still be subject to PSD review due to the NO_x emissions increase. No BACT for SO_2 will be required. Wood required would be 41,808 tons per year.

Scenario VI: Limited Use of New Boilers (coal burning only) and Boilers #5 and 6 at Current Operating Level

This scenario assumes use of the new boilers in conjunction with the existing coal-fired boilers, which are assumed to operate at the 1979 level (7,419 tons of coal per year). The new boilers will be limited to only 18,438 tons of coal per year. Under this scenario, credits for emissions will be allowed only for the amount emitted by the oil-fired boilers. In order to avoid the BACT requirement for SO_2 the sulfur content of coal to be used in the new and existing boilers must not exceed 0.52%. Use of higher than 0.52% sulfur coal will require BACT for SO_2. The modifications will also be major for NO_x.

Scenario VII: Limited Use of New Boilers (70% Coal and 30% Wood Burning) and Boilers #5 and 6 at Current Level of Operation

This scenario is similar to scenario VI but considers the use of coal and wood in the new boilers. Boilers #5 and 6 are assumed to operate at the 1979 level. If 0.98% sulfur coal is to continued to be used, the coal usage in the new boilers must be limited to 73% (13,460 tons per year) in order to avoid BACT for SO_2. Modifications will be considered major for NO_x. At higher sulfur coal, PSD review will be applicable for both SO_2 and NO_x.

Scenario VIII: Limited Use of New Boilers (at 100% Coal of Current Quality) and Increase Usage of Boilers #5 and 6

This scenario considers a further restriction on the use of the new boilers and increased usage of the old boilers. Quality of coal as currently used (0.98% S) was assumed. If BACT for SO_2 is to be avoided, a limit of 13,802 tons of coal to be burned in new boilers will be required. This will require the boilers 5 and 6 to burn 12,055 tons (an increase of 62% from the 1979 level of operation). Increased use of Boilers #5 and 6 is not restricted in any way and the boilers could burn 23,039 tons if operated at full capacity 365 days a year, 24-hours a day. Modifications will not trigger PSD requirements for any pollutant. However, use of coal with a sulfur content greater than 0.98% will trigger PSD review for SO_2.

Scenario IX: Unlimited Use of New Boilers and No Credits for Existing Boilers

This scenario assumes no restrictions on the amount of coal usage in the new boilers and claims no emissions credit from existing boilers. Operation of the new boilers at full capacity 24 hours per day, 365 days per year could burn 45,990 tons of coal per year, which is almost twice the amount of coal actually needed to meet the total annual heat demand. To avoid PSD review for SO_2, the sulfur content of coal has to be 0.05% or less. Since coal with such low sulfur content is not available, the modifications using more than 0.5% S coal will be considered major for NO_x and SO_2.

Emission Estimates

Emission estimates for the various scenarios mentioned earlier are given in Table 3.7. SO_2 emissions have been estimated for four different sulfur content of coal, 0.8, 0.98, 1.3 and 1.7. Emission factors for coal burning as given in Table 3.2 were used. For burning wood, the emission factors were taken from Table 1.6.1 of AP-42 and are reproduced in Table 3.8 for reference. AP-42 gives a range of emission factors for TSP, CO and VOC emissions from burning wood. In this calculation, the lowest[a] value was used. It is more likely that use of higher factors for CO and VOC will trigger PSD review for these pollutants. It should be further noted that VOC emissions in excess of 50 tons per year would require VOC emission offset because the area is nonattainment for ozone.

Allowable Emissions

The allowable emissions are presented in Table 3.9. These allowable emissions are only applicable to TSP, SO_2 and NO_x. There are no emission limits set for other pollutants. Two levels of emission limits were used in these calculations, one refers to the SIP emission limit and the other to those which may be required under PSD review. There are no SIP emission limits for any pollutant except TSP and SO_2.

Air Pollution Design Criteria

Based on emissions data presented in Tables 3.7 and 3.9 the efficiency of the control equipment was evaluated. These data are shown in Table 3.10. Whenever emissions exceed the allowable emissions, the emissions must be controlled to reduce them to the allowable emission levels. Control device efficiencies for TSP and SO_2 are presented for two levels of emission limits. For SO_2, four cases under each scenario were considered; these cases refer to the four level of sulfur content of the coal considered.

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[a] The August 1982 issue of the Journal of Air Pollution Control Association cites emission factors for wood burning even lower than those used here.

TABLE 3.7

EMISSIONS ESTIMATE[a] (NEW BOILERS)

	Emissions[c] in Tons Per Year							
		SO_2[d]						
Scenario[b]	TSP	0.80% S	0.98% S	1.3% S	1.7% S	CO	VOC	NO_x
I	1025	393	481	639	835	26	13	194
II	832	320	392	517	674	29	19	197
III	657	248	302	395	514	33	25	200
IV	518	194	234	304	393	35	29	202
V	105	31	31	31	31	42	42	209
VI	731	280	343	455	595	18	9	138
VII	554	211	257	338	441	22	15	141
VIII	547	210	257	341	446	14	7	104
IX[e]	1823	699	856	1136	1485	46	23	345

a Based on fuel consumptions given in Table 3.5 and emission factors from Tables 3.2 and 3.8.
b For description see Table 3.5.
c All emissions are uncontrolled emissions.
d SO_2 emissions are given for four sulfur content of coal (0.80, 0.98, 1.3 and 1.7% S).
e As will be shown in Chapter 6, a sulfur content of coal higher than 1.54% under this scenario will exceed the available PSD increment for SO_2.

TABLE 3.8

EMISSION FACTOR FOR WOOD BURNING

Pollutant	AP-42 Emission Factor (lb/ton)	Factor Used for Table 3.6 (lb/ton)
TSP	5-15	5
SO_2	1.5	1.5
CO	2-60	2
VOC	2-70	2
NO_x	10	10

TABLE 3.9

ALLOWABLE EMISSIONS
(New Boilers)

Pollutant	Emissions Limit (lb/MMBtu)	Allowable Emissions (ton/year) Scenarios I-V	Scenarios VI-VII	Scenario VIII	Scenario IX
TSP	0.1[a,b]	35	25	19	62
	0.5[a]	174	124	93	309
SO_2	2.4[a]	832	595	446	1481
	1.2[b]	416	297	222	740
NO_x	0.7[b]	243	173	130	432

a Refers to SIP emission limits.
b Refers to NSPS emission limits.

TABLE 3.10

REQUIRED EFFICIENCIES OF POLLUTION CONTROL DEVICES
TO MEET EMISSION LIMITS

		Required Control Efficiency (%)				
		TSP		SO_2		NO_x
Scenario	Case[a]	0.1 lb/MMBtu	0.5 lb/MMBtu	2.4 lb/MMBtu	1.2 lb/MMBtu	0.7 lb/MMBtu
I	a	96.5	83.0	--	--	--
	b	96.5	83.0	--	13.5	--
	c	96.5	83.0	--	34.5	--
	d	96.5	83.0	--	50.0	--
II	a	95.8	79.1	--	--	--
	b	95.8	79.1	--	--	--
	c	95.8	79.1	--	19.5	--
	d	95.8	79.1	--	38.3	--
III	a	94.5	73.3	--	--	--
	b	94.5	73.3	--	--	--
	c	94.5	73.3	--	--	--
	d	94.5	73.3	--	19.1	--
IV	a	93.2	66.4	--	--	--
	b	93.2	66.4	--	--	--
	c	93.2	66.4	--	--	--
	d	93.2	66.4	--	--	--
V	Not Applicable	66.6	--	--	--	--

Continued on Next Page

[a] Refers to sulfur content of coal, 0.79, 0.98, 1.3 and 1.7%.

-- Indicates not required.

Table 3.10 - Continued

		Required Control Efficiency (%)				
		TSP[b]		SO_2		NO_x
Scenario	Case[a]	0.1 lb/MMBtu	0.5 lb/MMBtu	2.4 lb/MMBtu	1.2 lb/MMBtu	0.7 lb/MMBtu
VI	a	96.5	83.0	--	--	--
	b	96.5	83.0	--	13.5	--
	c	96.5	83.0	--	34.5	--
	d	96.5	83.0	--	50.0	--
VII	a	95.3	77.6	--	--	--
	b	95.3	77.6	--	--	--
	c	95.3	77.6	--	12.1	--
	d	95.3	77.6	--	32.6	--
VIII	a	96.5	83.0	--	--	--
	b	96.5	83.0	--	13.5	--
	c	96.5	83.0	--	34.5	--
	d	96.5	83.0	--	50.0	--
IX	a	96.5	83.0	--	--	--
	b	96.5	83.0	--	13.5	--
	c	96.5	83.0	--	34.5	--
	d	96.5	83.0	--	50.0	--

a Refers to sulfur content of coal, 0.79, 0.98, 1.3 and 1.7%.
b Proposed control equipment (mechanical collector and a baghouse) normally achieves more than 99% removal efficiency for TSP.
-- Indicates not required.

Net Increase in Emissions

Net increase in emissions refers to the difference in emissions for the scenario under consideration and the emissions from the existing plant. For Scenarios I through V, it is assumed that boilers #1, 3 and 4 will be decommissioned and boilers #5 and 6 be designated as standby units. Under this consideration, the Base would be able to claim credits for emissions from all existing boilers at the Base. For Scenarios VI through VIII, credits could be claimed for emissions from boilers #1, 3 and 4 only. For Scenario IX, no emissions credits will be applicable. By subtracting emissions given in Table 3.1 from those in Table 3.7, the net increases in emissions were calculated and are shown in Table 3.11.

PSD Applicability

From Table 3.11 it is evident that the proposed modifications will be considered major because NO_x emissions under each scenario except Scenario VIII exceed the de minimus value of 40 tons per year. In addition, the proposed changes will be considered a major modification and subject to PSD review for SO_2 under Scenario I, II, III, VI, VII, VIII and IX for several sulfur contents of the coal.

BACT Review Requirement

Though Table 3.11 indicates that the source will be a PSD source and subject to the requirement of BACT for NO_x under most scenarios, the maximum emission ratio will be 0.6 lb per million Btu. This ratio (0.6 lb/MMBtu) is well below the NSPS limit applicable to boilers greater than 250 million Btu per hour capacity. Thus, the boilers could be easily justified as using BACT for NO_x. Other control techniques acceptable as BACT for NO_x control are low excess air, low NO_x burners, reduced air preheat, staged combustion air, etc.

For control of total suspended particulates, it is proposed to install a mechanical collector followed by a baghouse as part of the heating plant design. Such a control system can easily achieve more than 99% removal efficiencies. Hence, it can be easily demonstrated that the proposed control system is BACT for controlling total suspended particulates.

Under PSD review for SO_2, application of BACT might require flue gas desulfurization and/or burning low sulfur coal. One solution to avoid BACT review for SO_2 would be to limit the sulfur content of coal. Limits of sulfur contents of coal necessary to avoid BACT review are given in Table 3.12.

As Table 3.11 indicates the proposed modification will be subject to PSD review under most (all except Scenario VIII with 0.98% sulfur coal) scenarios. Since a PSD permit application has to be prepared anyway, it would be preferred to trigger the PSD review for SO_2 as well and thus avoid restrictions on amount of coal usage. Under PSD review, use of low sulfur coal could be demonstrated as BACT.

Restrictions which will determine the sulfur content of coal are as follows:

TABLE 3.11

NET INCREASE IN EMISSIONS

Scenario	Emissions in Tons Per Year							
		SO_2						
	TSP	0.80% S	0.98% S	1.3% S	1.7% S	CO	VOC	NO_x
I	995	38	126	284	480	13	8	65
II	811	-35	38	162	319	16	13	68
III	627	-107	-53	40	159	20	20	71
IV	488	-161	-121	-51	38	22	24	73
V	75	-324	-324	-324	-324	29	37	80
VI	713	63[a]	126	238	378	12	8	65
VII	536	-6	40	121	224	15	14	68
VIII	529	-7	40	124	229	8	6	31
IX	1823	699	856	1136	1485	46	23	345
De Minimus Values	25	40	40	40	40	100	40	40

[a] Requires 0.52% sulfur content coal to avoid triggering PSD for SO_2 (i.e., SO_2 emission increase of less than 40 tons per year).

TABLE 3.12

LIMITING SULFUR CONTENT TO
AVOID BACT REVIEW FOR SO_2

Scenario	Sulfur Content
I (100% coal)	0.80
II (80% coal, 20% wood)	0.98
III (60% coal, 40% wood)	1.3
IV (45% coal, 55% wood)	1.7
V (100% wood)	-
VI (100% coal)	0.52
VII (73% coal, 27% wood)	0.98
VIII (100% coal)	0.98
IX (100% coal)	0.05

1. The sulfur content of coal could in no case be greater than 1.7% because this is equivalent to 2.4 lbs per million Btu which is the limit imposed by state regulations.

2. A sulfur content of 1.54% or more will cause an exceedance of the available PSD increments under Scenario IX. Under other scenarios, a higher sulfur coal could be accomodated without exceeding the available PSD increments due to available emission credits under these scenarios.

3. New Source Performance Standard (NSPS) is used as guide in determining BACT. There are no NSPS for boilers in sizes as proposed at the Base. The NSPS applicable to larger boilers is 1.2 lb/million Btu which is equivalent to 0.85% S. Thus, the upper and lower bounds of sulfur content of coal would be 1.7 and 0.85%. A sulfur content in this range has to be demonstrated as BACT for SO_2 control. In a recent (September 1982) PSD permit application to Michigan Department of Natural Resources, Engineering-Science has demonstrated the use of 1.0% sulfur coal as BACT for two new 75 million Btu/hour input coal fired boilers.

Fugitive Emissions

Fugitive emissions are associated with material handling and storage. There would be an increase in fugitive particulate emissions due to an increase in the amount of coal and ash handled. At present, there are no controls on the coal handling system. Sources of fugitive emissions and estimated emissions under proposed modifications are given in Table 3.13 for Scenario I.

Emissions of Other Pollutants

In addition to five criteria pollutants, several other pollutants are also regulated under PSD regulations. Emissions of these pollutants are given in Table 3.14 for Scenario I. The data indicate that none of these pollutants will increase in amounts greater than the de minimus value. Emissions of these pollutants are given in Table 3.14 for Scenario I only. Under other scenarios, the emissions would be proportional to the amount of coal burned. These pollutants are not emitted from wood burning.

Stack Parameters

The heating plant dimensions are 132 feet long, 70 feet wide and a maximum height of 62 feet. Based on these dimensions, good engineering practice (GEP) stack height is estimated to be 155 feet. GEP stack height is generally recommended in order to avoid downwash conditions. In addition to this stack height, another stack height of 80 feet was modeled. For stack heights less than GEP stack height, a downwash analysis is performed in Chapter 6.

Conceptual design performed by Commonwealth Associates indicates that each boiler will be accompanied by an air preheater to provide undergrate

TABLE 3.13

FUGITIVE EMISSIONS[a]

Source	Estimated Emissions (tons/year)		
	Existing[b]	Proposed Scenario I[c]	Increase
Coal load-in	0.19	0.63	0.44
Vehicular Traffic	0.40	1.38	0.98
Coal load-out	0.22	0.75	0.53
Wind Erosion[d]	0.80	1.9	1.10
Conveying and Transfer	0.15	0.50	0.35
Ash handling	0.08	0.30	0.22
	1.84	5.5	3.62

a Emission factors from Technical Guidance for Control of Industrial Process Fugitive Particulate Emissions (Publication No. EPA-450/3-77-010).
b Based on 7,419 tons of coal
c Based on 25,857 tons of coal, for other scenarios it will be less.
d Assuming a 180 days supply to be in storage.

TABLE 3.14

EMISSIONS OF OTHER POLLUTANTS

Pollutant	Emissions in Tons per Year					
	Existing Boilers			New[c] Boilers (Scenario I)	Net Increase[d]	De Minimus Values
	#1, 3 & 4[a]	#5 & 6[b]	Total			
Arsenic	0.0012	0.0110	0.0122	0.0101	-0.0021	------
Asbestos	0	0	0	0	0	0.007
Beryllium	0.0008	0.0006	0.0014	0.0005	-0.0009	0.0004
Cadmium	0.0042	0.0039	0.0081	0.0035	-0.0046	------
Lead	0.0005	0.0019	0.0024	0.0018	-0.0016	0.6
Manganese	0.0012	0.0118	0.0130	0.0109	-0.0021	------
Mercury	0.0005	0.0001	0.0004	0.0001	-0.0003	0.1
Nickel	0.0978	0.0004	0.0982	0.0004	-0.0978	------
Vanadium	0.2444	0.0022	0.2466	0.0021	-0.2445	------

[a] Annual usage of 2,445,557 gal of #6 oil.
[b] Annual usage of 7,419 tons of coal and 96% control.
[c] Annual usage of 25,857 tons of coal and 99% control.
[d] Determined as difference between emissions from new boilers and existing five boilers.

and combustion air at a maximum of 350°F. The corresponding flue gas exit temperature from the air heater will be 350°F. Each boiler will be further equipped with a mechanical dust collector and a baghouse. Due to a combination of these equipment, exhaust gases will be cooler; however, it must be maintained above dew point to avoid acid formation and damage to the stacks. An exit gas temperature of 350°F was used for modeling purposes.

The volume of the exhaust gases depends upon the coal characteristics, percent excess air and temperature. Assuming 50% excess air, it is estimated that the flow rate for each boiler at full load for Scenario I would be approximtely 24,300 cubic feet per minute at 350°F. The total for the two boilers will be 48,600 cubic feet per minute.

The most widely used plume rise equations (Briggs equation) are based on the flow rate but can also accept stack diameter and velocity as inputs. For all practical purposes of modeling, stack diameters and velocity are not required if the flow rate is given. Assuming a stack diameter of 4.25 feet (same as the existing stacks) for each stack, the exit velocity will be 29 feet per second.

AVERAGE MONTHLY EMISSIONS

Based on logs of fuel consumption maintained by the Base for the year 1979, the average monthly heat inputs are shown in Table 3.15. Monthly heat inputs are also given as a fraction of the total annual usage. These factors were used in proportioning emissions and flow rates for the existing boilers for input to the model on a monthly basis.

OTHER SOURCES OF AIR POLLUTION

There would be no other sources of air pollution at the central heating plant.

LOCATION OF SOURCES

The only sources of air pollution at the heating plant will be the boilers. The location of the proposed heating plant is shown in Figure 3.1. The UTM coordinates of the plant are as follows:

Easting 470.4 km
Northing 5131.0 km

OTHER PSD SOURCES

Conversations[a] with Michigan DNR indicates that most probably no other sources have consumed any PSD increments in this area. Thus no other sources were considered. To make sure, DNR prefers that the clients

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[a] Telephone conversation with John Cardell, Michigan DNR, August 18, 1982.

TABLE 3.15

MONTHLY FUEL USE FACTOR

Month	Fuel Usage[a] Coal (tons)	Oil (gal)	Heat Input (MMBtu)	Heat Input Factor (% of annual)
January	1,587	257,210	80,022	14.4
February	1,000	318,280	73,153	13.2
March	43	454,370	67,269	12.1
April	387	266,910	49,225	8.8
May	828	78,150	33,595	6.0
June	352	105,290	24,768	4.4
July	662	1,400	17,972	3.2
August	463	71,490	22,829	4.1
September	376	110,010	26,098	4.7
October	599	194,850	44,430	8.0
November	568	261,447	53,288	9.6
December	554	326,150	62,327	11.4
Total	7,419	2,445,557	554,976	100.0

[a] Based on 1979 fuel consumption.


K.I. Sawyer
Study Area
LOCATION OF
CENTRAL HEATING PLANT
SCALE
1
0
1
Miles
1
0
1
Kilometers
N
HEATING PLANT
SAWYER AIRPORT
Sands Station
Uncle Tom Lake
Little Trout Lake
Plains
Stump Lake
Swanzy
Slough Lake
Airport Lake
Gwinn
New Swanzy
Blue Lake
Noren Lake
Irene Lake
Wilson Lake
Silver Lake
Little Lake
NORTH WESTERN
CHICAGO AND NORTH WESTERN
LAKE SUPERIOR AND
F O R S Y T H
EAST BRANCH
Halfway Creek
465
469
474
5138
5135
5124

visit their office and search their permit files to find out other sources which might have consumed the PSD increments.

GEP STACK HEIGHT

EPA has recently published good engineering practice (GEP) stack height regulations. These regulations are intended to prevent tall stacks from being used primarily as a dilution mechanism for sources which emit large amounts of pollutants. Furthermore, stacks should be of sufficient height to prevent aerodynamic downwash from nearby buildings. Air passing over a building may trap the plume in the building wake and bring the plume to the ground, thus resulting in high ground level concentrations. In general, GEP stack height is based on the nearby building height.

The GEP stack height was determined using the following relationship as given in EPA regulations.

$$Hg = H + 1.5\,L$$

where: Hg = GEP stack height
H = height of nearby structure or building
L = lesser dimension (height or width) of the nearby structure or building

Where the building height is less than the building width, the GEP stack height is given by:

$$Hg = H + 1.5\,H$$

$$Hg = 2.5\,H$$

Thus, a properly designed stack should be about two and one-half times the nearby building height.

Considering the height of the heating plant to be 62 feet, it will be necessary to have a stack height of 155 feet above ground level to meet GEP. A stack height lower than this could result in downwash conditions.

CHAPTER 4

BASELINE AIR QUALITY LEVELS

Sources subject to PSD regulations are required to perform an air quality analysis to show that: (1) the National Ambient Air Quality Standards (NAAQS) are not violated, and (2) the maximum allowable PSD increments are not exceeded. According to procedures established by Congress under the Clean Air Act (CAA) of 1970, the U.S. Environmental Protection Agency (EPA) promulgated the NAAQS for the protection of human health and welfare. These standards are given in Chapter 1, Table 1.1. The Clean Air Act (CAA) Amendments of 1977 further prescribed a set of firm increments which are not to be exceeded in those areas of the country which have ambient air quality levels better than the NAAQS. These maximum allowable increases were also shown earlier in Table 1.2.

In order to determine compliance with regulations, it is necessary to establish the existing ambient air quality levels for the area under consideration. U.S. EPA has further established procedures for determining the baseline concentrations. According to these procedures, the baseline air quality is defined as the ambient concentration at the time of the first complete PSD permit application in the area subject to PSD requirements. Once the baseline air quality level is established, in general it is not necessary for new applicants to remeasure or reanalyze for baseline air quality. This would be the first permit application in the area of concern. Current PSD regulations, however, require the use of measured ambient air quality data to establish the baseline air quality.

MEASURED AIR QUALITY DATA

The KI Sawyer AFB is located in Marguetee County, Michigan and falls in the federal AQCR 126. Though the Michigan Department of Natural Resources operates nine total suspended particulates samplers, five SO_2 monitors and one ozone monitor in this county, the air quality data in the vicinity of the Base is sparse. The nearest monitoring site is approximately 15 miles away. The measured air quality for 1980 is summarized in Table 4.1. The data indicate no violation of any ambient air quality standards.

BASELINE AIR QUALITY

Measured ambient air quality data were used to establish the baseline. The use of available air quality data from a local monitoring

TABLE 4.1

EXISTING AIR QUALITY ($\mu g/m^3$)
(Marquette County)

Site		TSP		SO_2			CO		NO_x	O_z
MASN[a]	Location	AGM	24-hour 2nd Maximum	AAM	24-hour 2nd Maximum	3-hour 2nd Maximum	1-hour 2nd Maximum	8-hour 2nd Maximum	AAM	1-Hour Maximum
52-010	Morgan Height Acock Medical Facility	19	65	--	--	--	--	--	--	--
52-011	Palmer Fire Dept. Smith Avenue, Palmer	43	147	--	--	--	--	--	--	--
52-012	Northern Michigan Univ. Sugar Loaf & Wright Marquette	25	69	--	--	--	--	--	--	--
52-014	IGA Store 200 S. Third Marquette	33	109	--	--	--	--	--	--	--
52-920	Shiras Pool Presque Isle Marquette	15	86	--	--	--	--	--	--	--
52-921	Lakeshore East North Side Marquette	24	145	--	--	--	--	--	--	--
52-922	Firestone Bldg. Hawley & Presque Isle Marquette	25	121	--	--	--	--	--	--	--
52-926	Lakeshore Center Lakeshore Blvd Marquette	20	67	--	--	--	--	--	--	--
52-927	Lakeshore West Lake Shore Blvd Marquette	14	39	--	--	--	--	--	--	--

a Michigan Air Sampling Network

Table 4.1 - Continued

Site		TSP		SO_2			CO		NO_x	O_z
MASN	Location	AGM	24-hour 2nd Maximum	AAM	24-hour 2nd Maximum	3-hour 2nd Maximum	1-hour 2nd Maximum	8-hour 2nd Maximum	AAM	1-Hour Maximum
52-901	Presque Isle E. Wright West Side No. 1 (Marquette)	--	--	1	26	79	--	--	--	--
52-902	East Site No. 2 Shiras Park (Marquette)	--	--	5	26	105	--	--	--	--
52-904	North Site No. 3 Shiras Pool Marquette	--	--	4	79	262	--	--	--	--
52-906	Lakeview Arena Pine Street Marquette	--	--	3	26	52	--	--	--	--
52-911	H.J. Bothwell School Mesnard & Tierney Marquette	--	--	2	38	210	--	--	--	--
52-013	DNR Office County Rd. 550 Big Bay	--	--	--	--	--	--	--	--	196

AGM - annual geometric mean
AAM - annual arithmetic mean

measured air quality for TSP, SO_2 and ozone was determined on the basis of highest measured air quality in the county. For other pollutants for which there were no monitoring data for the county, measured data from other representative sites were used.

Baseline air quality data is shown in Table 4.2.

AVAILABLE PSD INCREMENTS

The maximum PSD increments allowed under CAA amendments of 1977 are given in Chapter 1, Table 1.2. However, the Michigan Department of Natural Resources allows only 80% of the maximum allowable increment. When the ambient air quality levels approach the ambient air quality standards, the allowable PSD increments would be the difference between the standards and the baseline whenever this difference is less than the allowable PSD increments. A comparison of the measured ambient air quality with the standards indicates that all the PSD increments are available for consumption by new or modified sources.

TABLE 4.2

BASELINE AIR QUALITY LEVELS

Pollutant	Averaging Time	Concentration (micrograms per cubic meter)
TSP[a]	Annual	15
	24-hour	86
SO_2[b]	Annual	4
	24-hour	79
	3-hour	262
CO[c]	8-hour	5,500
	1-hour	6,800
Ozone[d]	1-hour	196
NO_x[e]	Annual	21

a Based on monitoring site at Shiras Pool, Presque Isle, Marquette.
b Based on monitoring site at Northside No. 3, Shiras Pool.
c Based on data measured in Huron County, Rubicon Township.
d Based on data measured at the DNR office in Marquette County.
e Based on data measured in Saint Clair County.

CHAPTER 5

METEOROLOGICAL AND CLIMATOLOGICAL CONSIDERATIONS

Air emissions to the atmosphere are transported and dispersed to a varying degree depending upon the meteorological and topographical conditions of the area. The airborne phase which is initiated with the emissions is followed by their transport and diffusion through the atmosphere. The cycle is completed when the pollutants are deposited on vegetation, soil, and other surfaces; when they are washed out of the atmosphere by rain; or when they escape into space. In some cases, the pollutants may be reinserted into the atmosphere by the action of the wind.

PARAMETERS OF INTEREST

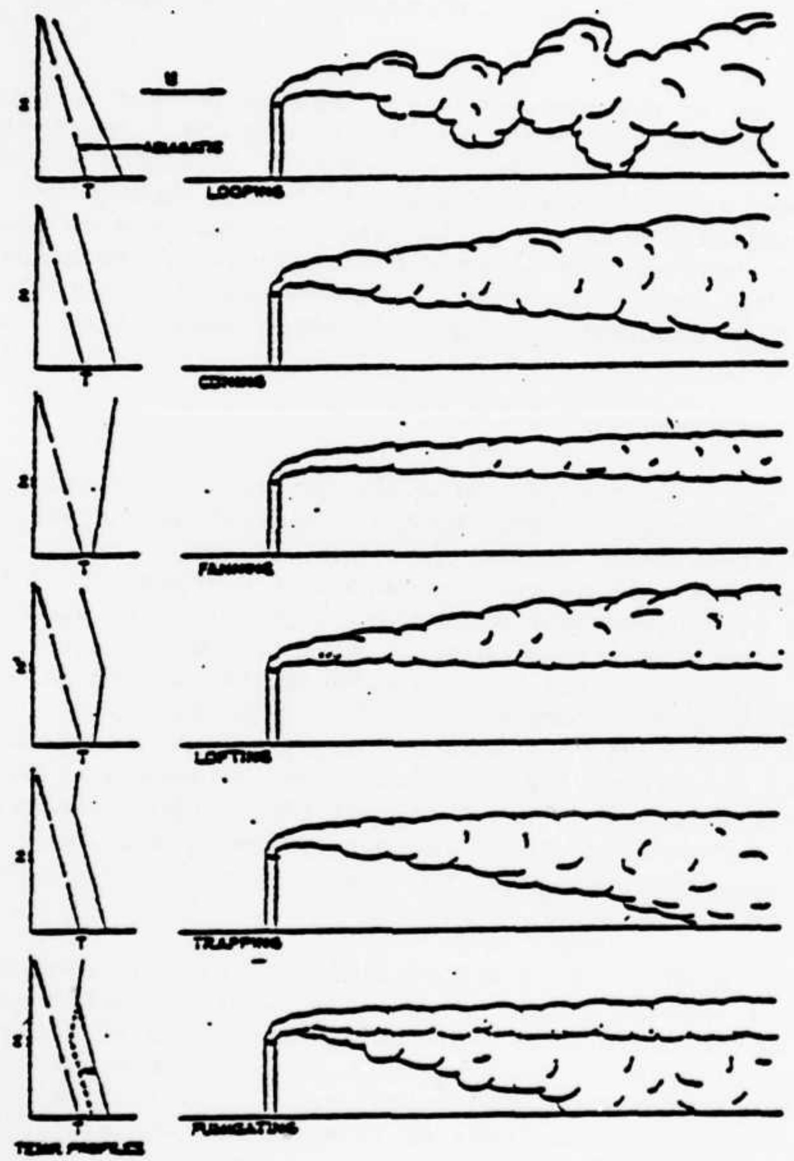
The important elements governing the dispersion and dilution of air pollutants and consequently their downwind concentrations are wind speed, direction, and atmospheric stability. Wind direction and speed determine where the pollutants will go and the degree of downwind dilution. The concentrations at any receptor site depend upon the wind speed and the persistence of the wind direction which affects that receptor. The stability of the atmosphere, which is related to the way the temperature changes with elevation, determines the extent of the vertical and horizontal dispersion of these pollutants. Topographical features, including wake effects of buildings near the stack, require special investigation. Their importance arises from the fact that they produce changes in the meteorological parameters. These factors, properly combined, are used to estimate, the concentration of pollutants from a single source or a family of sources.

The influence of the wind and stability is evident whenever the effluent forms a visible plume. Terms like fanning, fumigation, coning, looping, and lofting have been empirically associated with stability and are used to describe the plume behavior. These terms and their relation to the temperature variation with height are illustrated in Figure 6.1. The nonvisible effluent plume behaves in a similar manner.

CLIMATOLOGY OF THE AREA

KI Sawyer AFB is located in the Upper Penisula of Michigan. The area around the base is flat and has an altitude of about 1160 feet above mean sea level. The highest point in the vicinity is about 1200 feet above mean sea level.

Plume Types for Various Stabilities



Plume types for various thermal stabilities. The top three occur with uniformly varying temperature with elevation: unstable, adiabatic (neutral), and stable. The bottom three are caused by discontinuities in stability of atmospheric layers.

SOURCE: G.H. Strom. 1976: Transport and Diffusion of Stack Effluents. In Air Pollution, 3rd ed.,

The climiate of the region is one of considerable variation. The climate is heavily tempered due to the proximity of Lakes Superior and Michigan. [The typical North American cold wave, which so frequently sweeps down from the Northwest, attended by strong northwest winds, is considerably tempered in severity as it crosses the wide stretches of comparatively warm water of the lakes. The temperature is often raised by 15 to 20°F.] The annual precipitation ranges from 26 to 34 inches.

LAND USE

The city of Gwinn is just south of the Base. There are no industrial or major commercial activities in the area.

METEOROLOGICAL CONSIDERATIONS

Wind speed and directions are routinely observed and recorded at National Weather Service first order stations and at many military airports. Stability can be determined from measurements of vertical gradient of wind and temperature. However, these observations are not routinely available and the more common technique is to use observation of cloud cover and wind speed in the framework suggested by Pasquill and Gifford and presented in Turner's Workbook.[a] The basic relationship is given in Table 5.1 where D is neutral stability; A, B and C are unstable classes; and E and F are stable classes.

METEOROLOGICAL DATA USED IN THE ANALYSIS

For a dispersion model to provide useful and valid results, the meteorological data used must be representative of the transport and dispersion conditions in the vicinity of the plant that the model is attempting to simulate. The representative of the data is dependent on: the proximity of the meteorological monitoring site to the plant, complexity of the terrain in the area, exposure of the monitoring instruments, and the period of time during which the data were collected. The representativeness of the data can be adversely affected by large distances between the source and receptors of interest and valley-mountain, land-water and urban-rural characteristics of the plant area.

As previously stated, the meteorological data required as a minimum to describe transport and dispersion in the atmosphere are wind direction, wind speed, atmospheric stability and mixing height or related indicators of atmospheric turbulence and mixing. EPA prefers that the meteorological data base used with the air quality models include several years of data. Such a multi-year data base allows the consideration of variations in meteorological conditions that occur from year-to-year. The exact number of years needed to account for such variations in meteorological conditions is uncertain and depends on the climatic extremes in

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[a] D. Bruce Turner, Workbook of Atmospheric Dispersion Estimates, 1969.

TABLE 5.1

DEFINITION OF STABILITY CATEGORIES[a,b]

Surface Wind Speed (At 10 Meters) Meters/Sec[c]	Day			Night	
	Incoming Solar Radiation			Thinly Overcast or	
	Strong	Moderate	Slight	<4/8 Cloud	>3/8 Cloud
<2	A	A-B	B		
2-3	A-B	B	C	E	F
3-5	B	B-C	C	D	E
5-6	C	C-D	D	D	D
>6	C	D	D	D	D

a Source: D. Bruce Turner, Workbook of Atmospheric Dispersion Estimates, 1969.

b The neutral class, D, should be assumed for overcast conditions during day or night.

c To convert to miles per hour, multiply meters per second by 2.24.

a given area. EPA suggests that five years generally yields an adequate meterological data base.

The base is located in a flat terrain. Hourly surface observations made at the base in 1964 were used in this analysis. Upper air data used in the analysis were those observed at Sault Ste. Marie in 1964. These data were processed to produce required inputs to the air quality models used.

The basic parameters of wind speed, wind direction and stability classes were combined into a joint frequency distribution. This three-way joint frequency distribution could be further combined into a two-way joint frequency distribution. Such a distribution is shown in Table 5.2 ˆor comparison purposes.

TABLE 5.2

JOINT FREQUENCY DISTRIBUTION OF WIND SPEED, WIND DIRECTION, AND STABILITY CLASS AT KISAWYER AFB

	WIND SPEED (KTS.)							AVERAGE	STABILITY CLASS					
DIRECTION	0-3	4-6	7-10	11-16	17-21	>21	TOTAL	WS	A	B	C	D	E	F
N	1.8	1.4	2.3	3.6	0.9	0.4	10.5	10.0	0.0	0.2	0.4	7.7	0.4	1.7
NNE	1.2	1.7	2.6	2.0	0.3	0.1	7.8	8.5	0.0	0.4	1.0	5.0	0.5	0.8
NE	0.7	1.4	1.5	0.8	0.0	0.0	4.4	7.2	0.1	0.3	0.9	2.4	0.3	0.5
ENE	0.8	1.0	0.7	0.1	0.0	0.0	2.6	5.3	0.1	0.4	0.4	1.1	0.2	0.4
E	0.9	1.1	0.5	0.0	0.0	0.0	2.5	4.5	0.0	0.2	0.3	1.2	0.2	0.5
ESE	0.5	0.5	0.4	0.1	0.0	0.0	1.5	5.1	0.0	0.2	0.1	0.9	0.1	0.3
SE	0.1	0.5	0.7	0.2	0.0	0.0	1.9	6.6	0.0	0.1	0.1	1.3	0.1	0.2
SSE	0.6	0.9	1.5	0.8	0.1	0.0	3.8	7.8	0.0	0.2	0.2	2.7	0.3	0.4
S	1.5	2.2	3.7	4.5	1.1	0.4	13.4	10.0	0.0	0.2	0.8	9.9	0.7	1.7
SSW	2.0	3.0	3.8	3.1	0.6	0.2	12.7	8.5	0.0	0.1	0.7	7.4	1.4	3.0
SW	1.6	2.1	2.0	1.4	0.4	0.1	7.6	7.7	0.0	0.3	0.8	4.0	0.8	1.7
WSW	1.3	1.4	1.1	0.7	0.2	0.1	4.7	6.9	0.0	0.2	0.6	2.3	0.4	1.3
W	2.4	2.4	2.2	1.5	0.1	0.0	8.6	6.7	0.0	0.3	0.9	4.0	1.0	2.3
WNW	1.7	1.8	2.0	1.3	0.1	0.0	6.8	6.8	0.0	0.1	0.6	3.4	0.8	2.0
NW	1.2	1.1	1.9	1.7	0.0	0.0	5.9	7.9	0.0	0.1	0.5	3.8	0.5	1.0
NNW	1.0	0.9	1.6	1.7	0.1	0.0	5.3	8.4	0.0	0.1	0.3	3.8	0.3	0.8
TOTAL	19.5	23.4	28.4	23.5	3.8	1.4		8.1	0.3	3.5	8.5	61.1	8.0	18.7
A	0.2	0.1	0.0	0.0	0.0	0.0								
B	1.5	1.1	0.9	0.0	0.0	0.0								
C	1.1	1.8	4.6	0.9	0.0	0.0								
D	4.1	9.6	19.6	22.6	3.8	1.3								
E	0.0	4.6	3.4	0.0	0.0	0.0								
F	12.6	6.1	0.0	0.0	0.0	0.0								

CHAPTER 6

AIR QUALITY IMPACTS

The statutory and regulatory limits that apply to air quality impacts from major sources are discussed in Chapter 1. Baseline air quality levels and available PSD increments are discussed in Chapter 4. To ensure that these limits are not exceeded, atmospheric dispersion models were used to determine the potential impacts on air quality that might be caused by the emissions from proposed modifications of the Central Heating Plant at KI Sawyer AFB. A number of different emission scenarios were analyzed to determine the optimum permitting strategy. Emissions under these scenarios are discussed in Chapter 3. This chapter presents the modeling results and an analysis of the predicted air quality impacts.

ANALYSIS OBJECTIVE

The primary objective of the modeling analysis was to determine the air quality impacts under different emission scenarios. A number of emission scenarios consisting of different coal/wood combinations and emission credits for existing boilers were analyzed. Several scenarios based on exceedance of the NAAQS, and 50% and 100% consumption of the PSD increment were also considered in order to determine the maximum allowable SO_2 emissions. The SO_2 emissions for these scenarios are based on predicted air quality impacts. The general methodology used in the analysis is described in the following sections.

MODELING METHODOLOGY

EPA-approved atmospheric dispersion models were used to evaluate the impact of emissions from the new boilers. Inputs to the models included pollutant emission rate, source geometry, stack characteristics and meterological data. A single point source model, CRSTER, was used to determine the air quality impacts for short-term periods, such as 3-hour and 24-hour averages and long-term (annual) averages. The actual model used was a modified version of EPA's CRSTER model. This modification was performed by Engineering-Science for the U.S. EPA Region IV to extend the capability of the model to evaluate impacts from multiple point sources. Downwash analysis was performed using Huber-Snyder procedures as incorporated in the Industrial Source Complex (ISC) model. All these models are Gaussian plume models which have been extensively used and validated for air quality impacts. These models assume that the distribution of pollutant concentrations about the plume axis in the horizontal and vertical directions is Gaussian or normal. Detailed descriptions of these models are given in Appendix C.

MODEL INPUTS

Basic inputs to the models are emissions and meteorological data. In addition, the models require a grid of receptors at which the concentrations are to be computed. These model inputs are discussed below.

Emission Data

To determine the impact of the emissions from the existing boilers, actual emissions, as given in Table 3.1, were used in the analysis. Annual emissions were broken down into monthly emissions using factors given in Table 3.15.

Since short-term concentrations (3-hour and 24-hour averaging periods) are of critical importance, the impact of the new boilers were modeled at maximum daily emissions which were determined assuming full load operation of the boilers 24 hours a day. Furthermore, since SO_2 emissions from burning wood is much less than that from coal burning, it was assumed that only coal was being used during the entire 24-hour period. To present a worst case for Scenarios I through VIII it was assumed that one of the new boilers and both of existing coal fired boilers were operating at full load. For Scenario IX both new boilers were assumed to be operating at full load.

Meteorological Data

Meteorological data used in the analysis include hourly surface observations taken at the K. I. Sawyer Airfield and upper air data taken at the Sault Ste. Marie airport for the year 1964.

Receptor Grids

Each model requires a grid of receptors at which the air quality impacts are to be evaluated. A rectangular coordinate system was used to define the grid receptors. Receptor grid spacing is of critical importance for any modeling analysis. Receptors must be chosen in order to determine the maximum impact from the sources being modeled. Yet, it is impractical to model an infinite number of receptors. In the analyses performed here, a grid spacing of 1 km was used.

DISCUSSION OF RESULTS

The critical issue which will determine whether the new boilers will be permitted is the consumption of Class II PSD increments for sulfur dioxide if the NAAQS are not exceeded first. Only sulfur dioxide emissions were modeled. The analysis of the PSD increment consumption and compliance with NAAQS follows.

PSD INCREMENT CONSUMPTION

PSD increments were established for Class I and II areas for the pollutants sulfur dioxide and total suspended particulates. The maximum permissible levels over baseline air quality levels are defined in Chapter 1. Discussed below are the PSD increments consumed under different scenarios analyzed.

Air quality impacts of SO_2 emissions were modeled using actual monthly emissions in 1979 and are summarized in Table 6.1. Figures 6.1 through 6.3 present the annual average, 24-hour maximum and 3-hour maximum SO_2 concentrations respectively.

Maximum air quality impacts from the new boilers are summarized in Table 6.2. As Table 6.2 indicates the maximum impacts under Scenarios I through IX are more or less the same. This is because the maximum impacts were determined assuming boilers operating at full load and burning 100% coal throughout the day. The slight difference in predicted impacts between Scenarios I through VIII and those under IX are due to the fact that under Scenarios I through VIII, one new and two existing boilers were assumed to be operating to represent the worst case, whereas in Scenario IX the two new boilers are assumed operating at full load. The existing boilers have different stack characteristics than those of the new boilers. For determining the maximum annual impact, the boilers were assumed operating at full load throughout the year.

Figures 6.4 through 6.6 show the annual, 24-hour maximum and 3-hour maximum SO_2 concentration for Scenarios I-V when burning 0.98% S coal. Maximum impacts when burning coal with different sulfur content can be easily obtained by simple proportion. The maximum increase in air quality impacts was determined by examining the maximum difference in concentration at each receptor from existing boilers and those from the new boilers. The results are summarized in Table 6.3 for 0.98% S coal. PSD increment consumptions under all scenarios with different sulfur content coal are summarized in Table 6.4.

It is to be noted here that in determining the PSD increments shown in Tables 6.3 and 6.4, the following credits for existing boilers apply.

Scenarios I-V: Credits for boilers 1,3,4,5 and 6
Scenarios VI-VIII: Credits for boilers 1, 3 and 4
Scenario IX: none

Table 6.3 clearly shows the differences due to different emission credits applicable to the various scenarios.

Maximum SO_2 PSD increment consumptions for Scenarios I-V when burning 0.98% coal are shown in Figures 6.6 through 6.9 for the annual, 24-hour and 3-hour averaging time periods. Maximum PSD increment consumption for Scenario IX when burning 1.54% sulfur coal is shown in Figure 6.10 for the 24-hour averaging time period. This sulfur content (1.54%) results in consumption of all of the 24-hour PSD increment available for SO_2 before any other increments are fully consumed, and this represents the maximum sulfur content which can be permitted under Scenario IX. Maximum PSD increment consumption under Scenario IX when burning 1.0% sulfur coal can be obtained by direct proportion from Figure 6.10. No plots of TSP concentrations were made because the predicted concentrations are very low as evident from results given in Table 6.5.

ATTAINMENT OF NAAQS

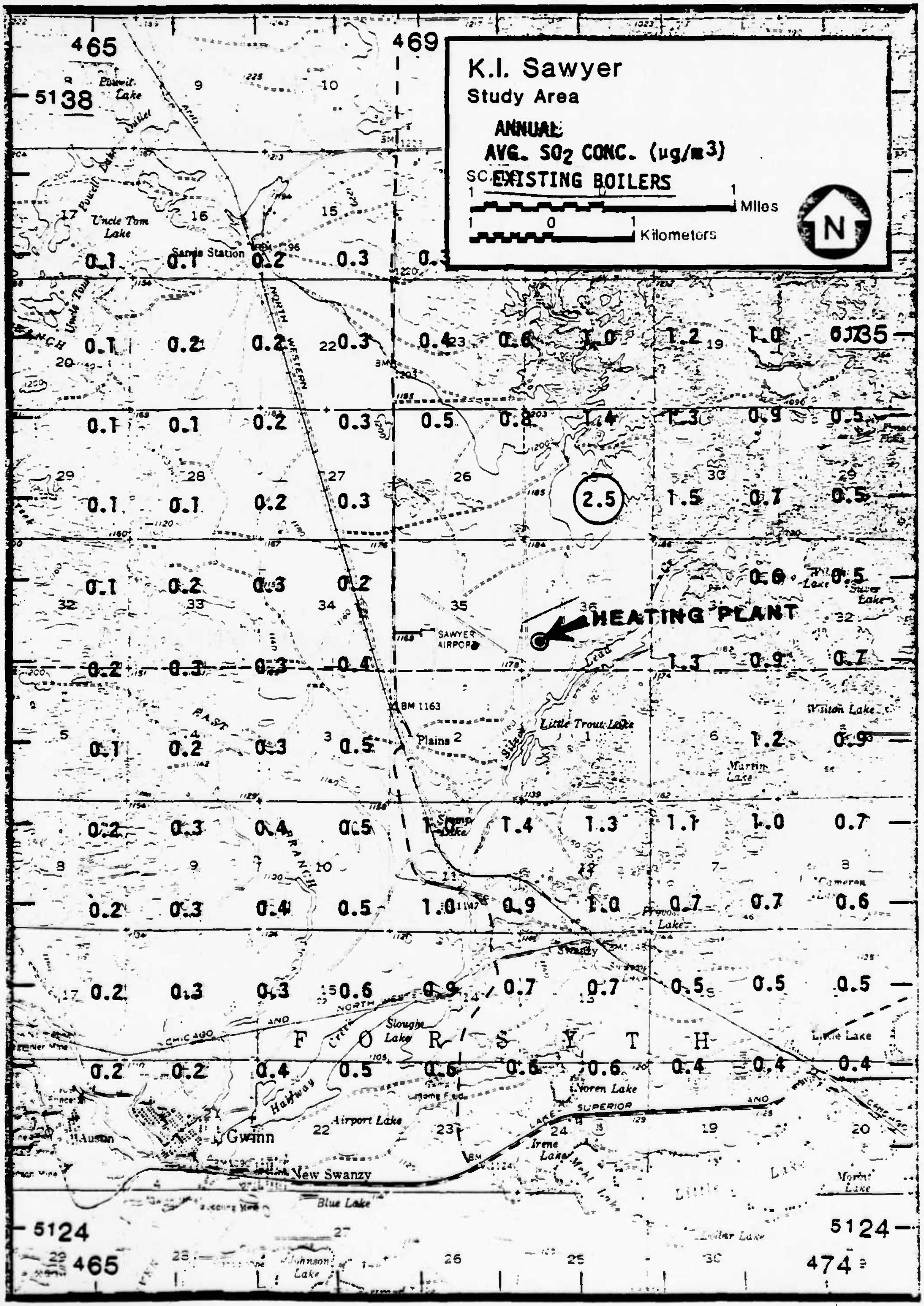
A permit can not be granted to construct or modify a major source if the emissions from the proposed source would cause a violation of the NAAQS or preclude the attainment of NAAQS. In Chapter 4, the existing

TABLE 6.1

SO_2 IMPACTS OF EXISTING PLANT[a]

Averaging Time	Maximum SO_2 Concentration ($\mu g/m^3$)
Annual Average	2.5
24-hour Maximum	30.4
3-hour Maximum	90.8

[a] Maximum SO_2 concentrations predicted outside the boundaries of the Air Force Base only were considered.


K.I. Sawyer
Study Area
ANNUAL
AVG. SO_2 CONC. (ug/m3)
EXISTING BOILERS
Miles
Kilometers
N
HEATING PLANT
SAWYER AIRPORT
Little Trout Lake
Plains
Gwinn
New Swanzy
Airport Lake
Blue Lake
F O R S Y T H
465
469
5138
5135
5124
474

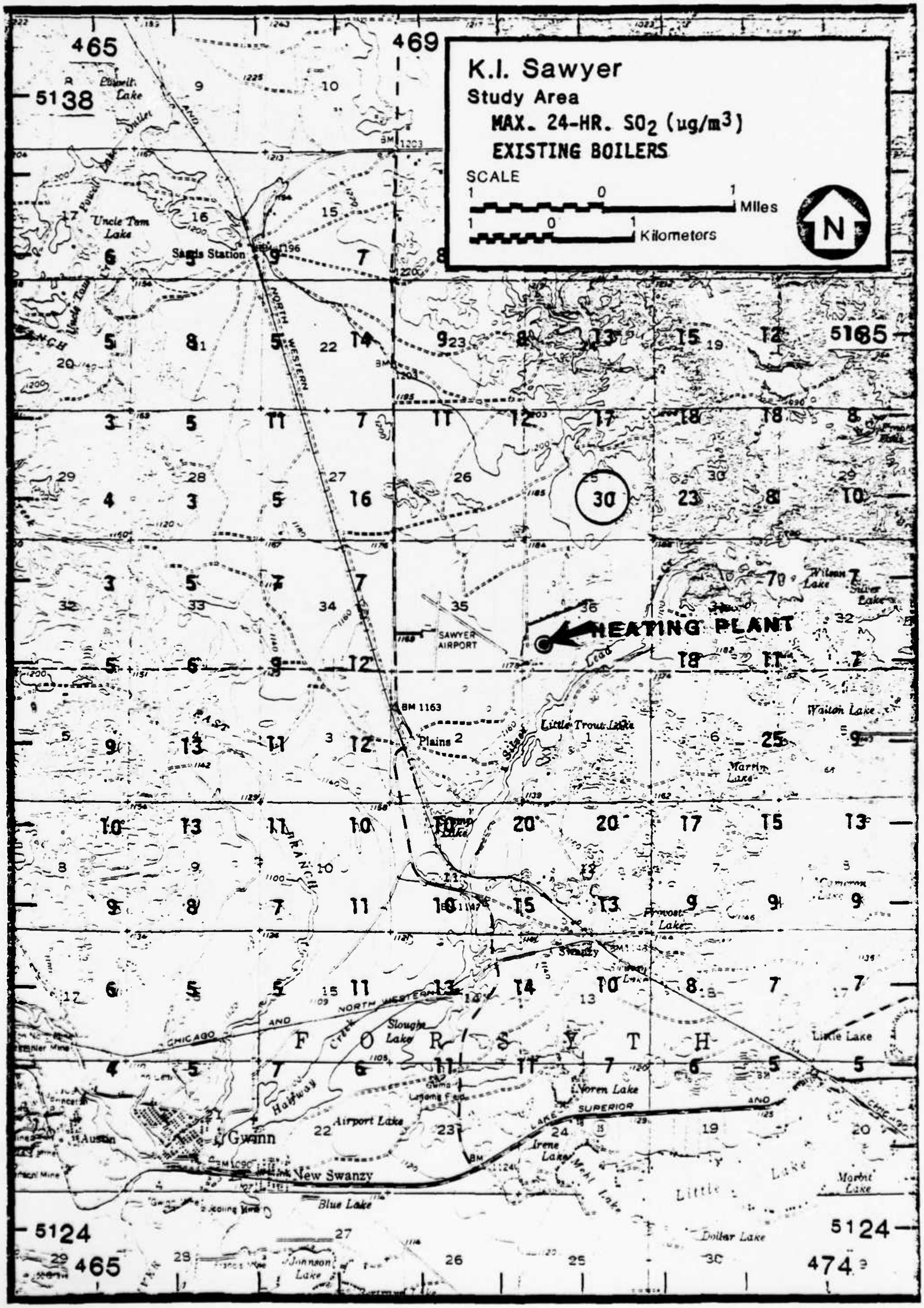
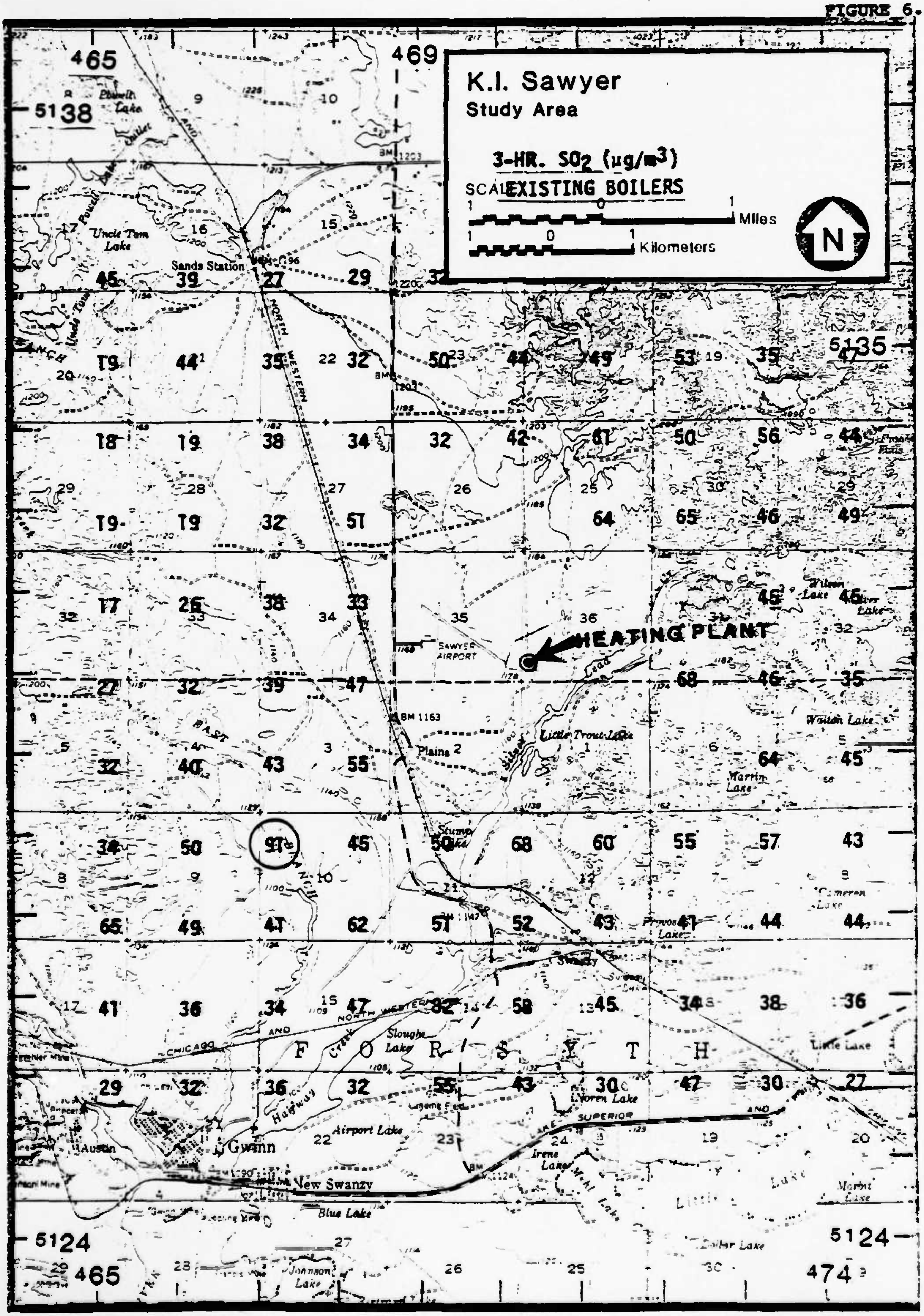

K.I. Sawyer
Study Area
MAX. 24-HR. SO_2 (ug/m^3)
EXISTING BOILERS
SCALE
1 0 1 Miles
1 0 1 Kilometers
N
HEATING PLANT
SAWYER AIRPORT
Sands Station
Uncle Tom Lake
Little Trout Lake
Plains
Walton Lake
Martin Lake
Wilson Lake
Silver Lake
Slough Lake
Airport Lake
Gwinn
New Swanzy
Blue Lake
Dollar Lake
Little Lake
Irene Lake
F O R S Y T H
CHICAGO AND NORTH WESTERN
LAKE SUPERIOR AND
465
469
474
5138
5124
5165

FIGURE 6.3



K.I. Sawyer
Study Area
3-HR. SO_2 (μg/m³)
EXISTING BOILERS
Miles
Kilometers
N
HEATING PLANT
SAWYER AIRPORT
Sands Station
Uncle Tom Lake
Little Trout Lake
Plains
Wilson Lake
Walton Lake
Martin Lake
Cameron Lake
Provost Lake
Swanzy
Slough Lake
Little Lake
Airport Lake
Gwinn
Austin
New Swanzy
Blue Lake
Irene Lake
Johnson Lake
F O R S Y T H

TABLE 6.2

MAXIMUM SO_2 IMPACTS OF NEW PLANT
(When Burning 0.98% Sulfur Coal)

	Maximum SO_2 Concentration ($\mu g/m^3$)	
Averaging Time	Scenario I-VIII	Scenario IX
Annual Average	5.2	4.7
24-hour Maximum	49.4	46.5
3-hour Maximum	125.5	120.0

FIGURE 6.4

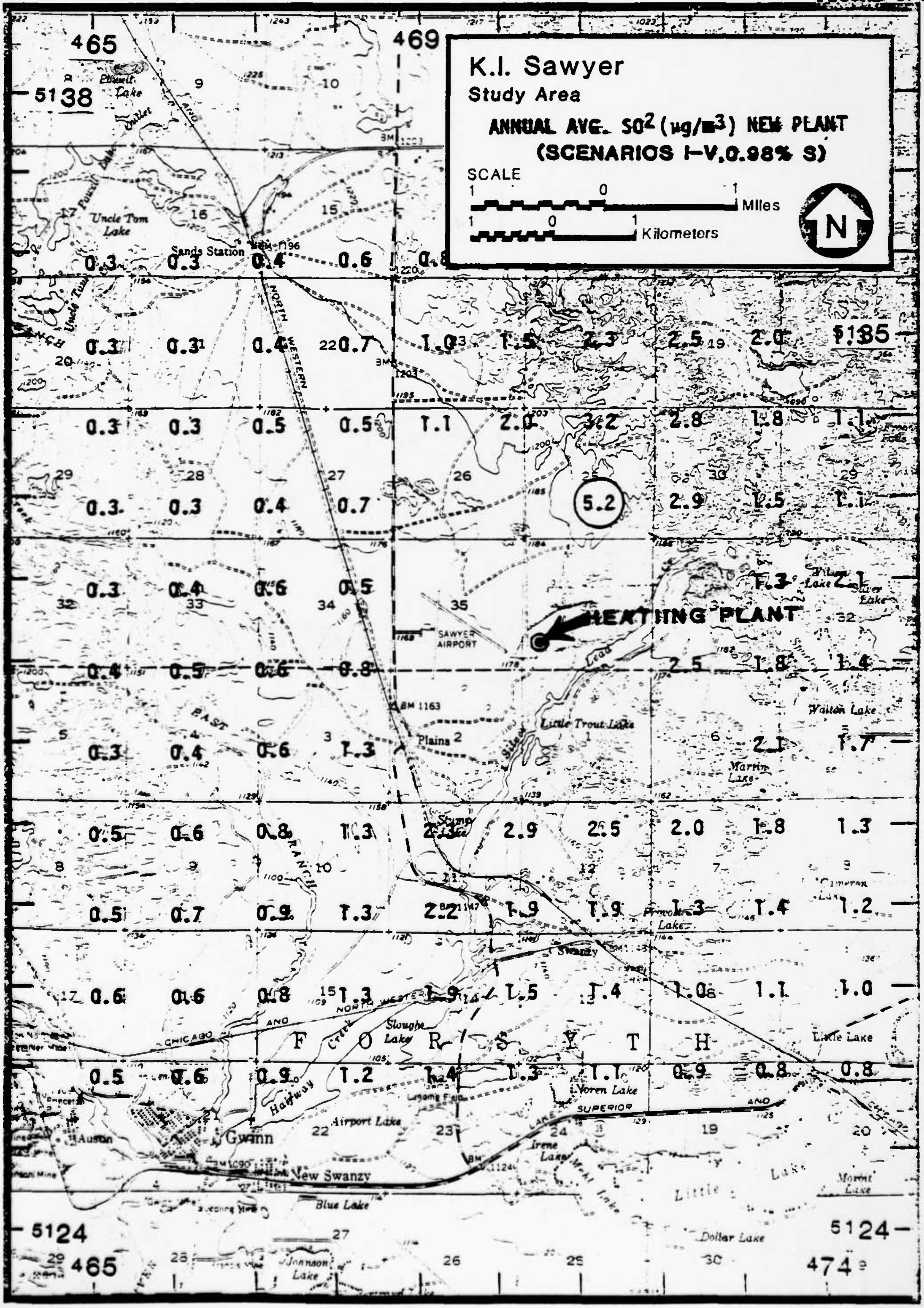
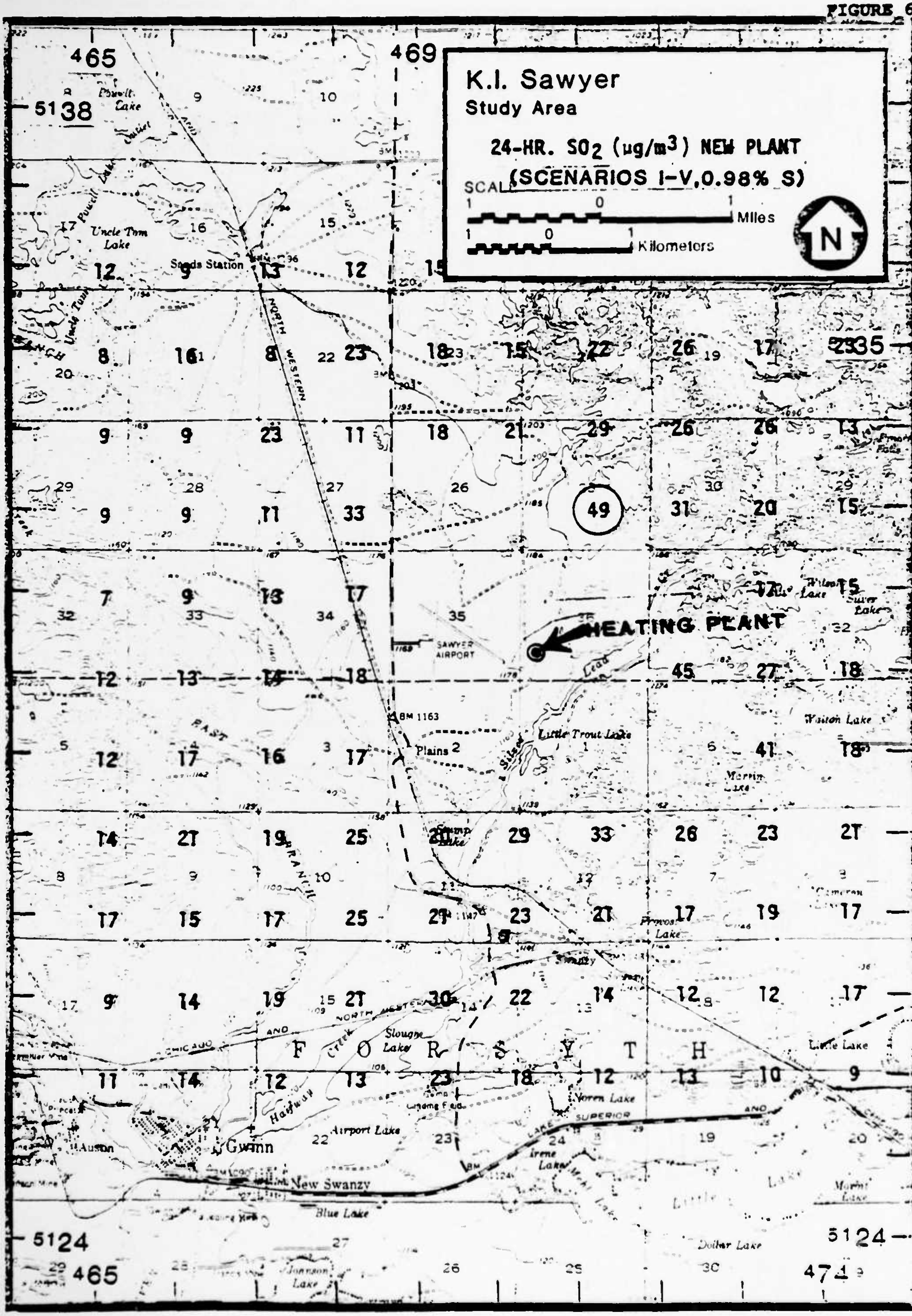

K.I. Sawyer
Study Area
ANNUAL AVG. SO2 (µg/m3) NEW PLANT
(SCENARIOS I-V, 0.98% S)
SCALE
Miles
Kilometers
N
HEATING PLANT
SAWYER AIRPORT
Sands Station
Uncle Tom Lake
Little Trout Lake
Plains
Swanzy
Gwinn
New Swanzy
Airport Lake
Blue Lake
Slough Lake
Noren Lake
Irene Lake
Dollar Lake
Walton Lake
Martin Lake
Little Lake
F O R S Y T H
465
469
474
5138
5135
5124
5.2

FIGURE 6.5


K.I. Sawyer
Study Area
24-HR. SO_2 (µg/m^3) NEW PLANT
(SCENARIOS I-V,0.98% S)
SCALE
Miles
Kilometers
N
HEATING PLANT
SAWYER AIRPORT
Sands Station
NORTH WESTERN
Uncle Tom Lake
Powell Lake
Little Trout Lake
Plains
Walton Lake
F O R S Y T H
Slough Lake
Airport Lake
Gwinn
New Swanzy
Blue Lake
Irene Lake
Johnson Lake
Dollar Lake
Little Lake
465
469
5138
5135
5124
474

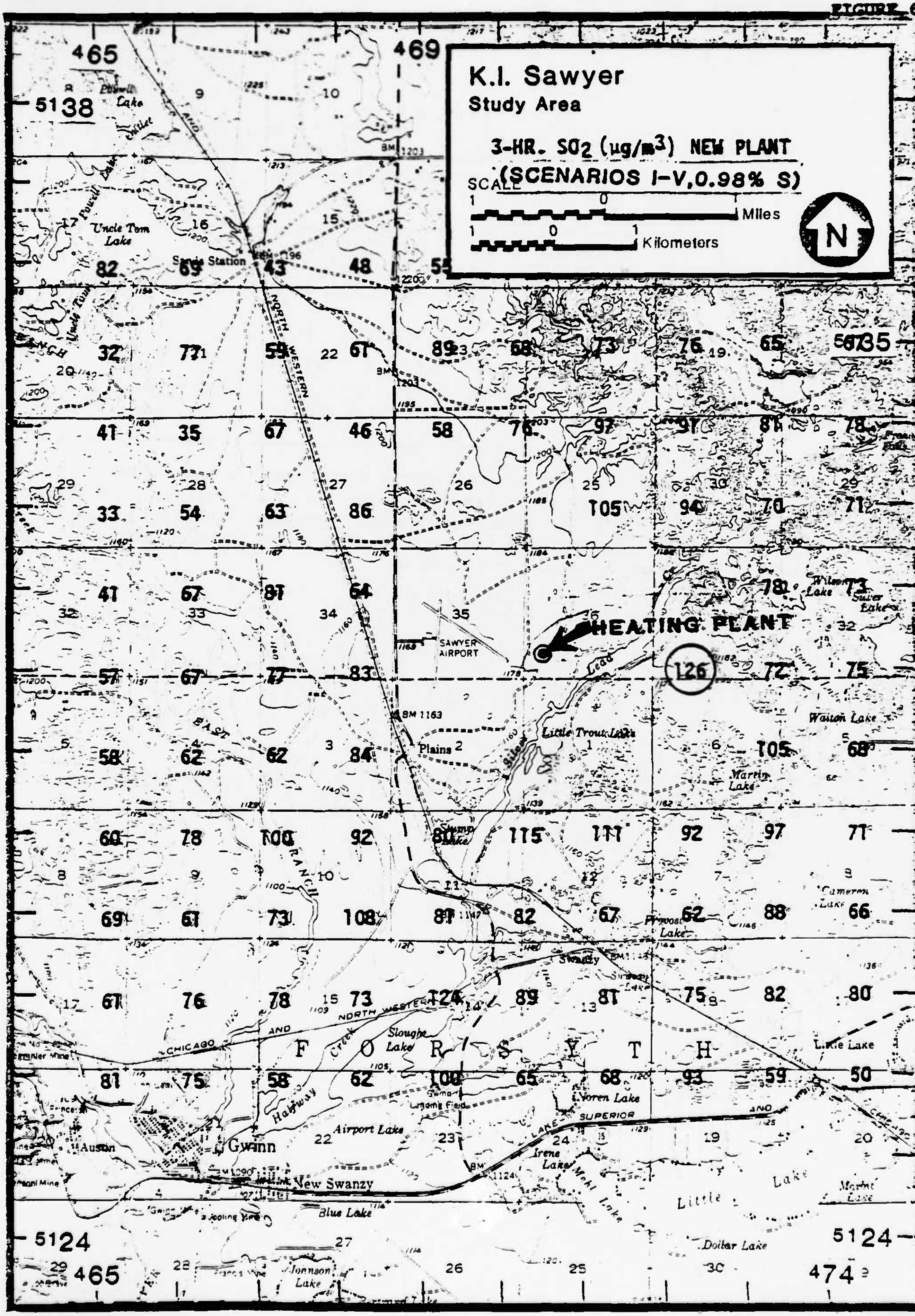

K.I. Sawyer
Study Area
3-HR. SO2 (µg/m3) NEW PLANT
(SCENARIOS I-V,0.98% S)
SCALE
Miles
Kilometers
N
HEATING PLANT
SAWYER AIRPORT
126
82 69 43 48 55
32 77 59 61 89 68 73 76 65
41 35 67 46 58 76 97 97 81 78
33 54 63 86 105 94 70 71
41 67 81 64 78 73
57 67 77 83 72 75
58 62 62 84 105 68
60 78 100 92 80 115 111 92 97 71
69 61 73 108 81 82 67 62 88 66
61 76 78 73 124 89 81 75 82 80
81 75 58 62 100 65 68 93 59 50
Uncle Tom Lake
Sands Station
NORTH WESTERN
Plains
Little Trout Lake
Wilson Lake
Watson Lake
Martin Lake
Swanzy
Slough Lake
CHICAGO AND NORTH WESTERN
F O R S Y T H
LAKE SUPERIOR
Gwinn
New Swanzy
Airport Lake
Blue Lake
Dollar Lake
5138
5124
465
469
474

TABLE 6.3

MAXIMUM INCREASE IN SO_2 IMPACTS
(When Burning 0.98% Sulfur Coal)

	SO_2 Concentration[a] ($\mu g/m^3$)		
Averaging Time	Scenario I-V	Scenario VI-VIII	Scenario IX
Annual Average	2.7	3.7	4.7
24-hour Maximum	26.5	33.6	46.5
3-hour Maximum	57.9	84.2	120.0

[a] Numbers under this column may not always correspond to the algebraic difference between values in Tables 6.1 and 6.2. The maximum difference is the maximum of the differences for each receptor. The absolute maximum impact from the existing and modified plant may not always occur at the same receptor.

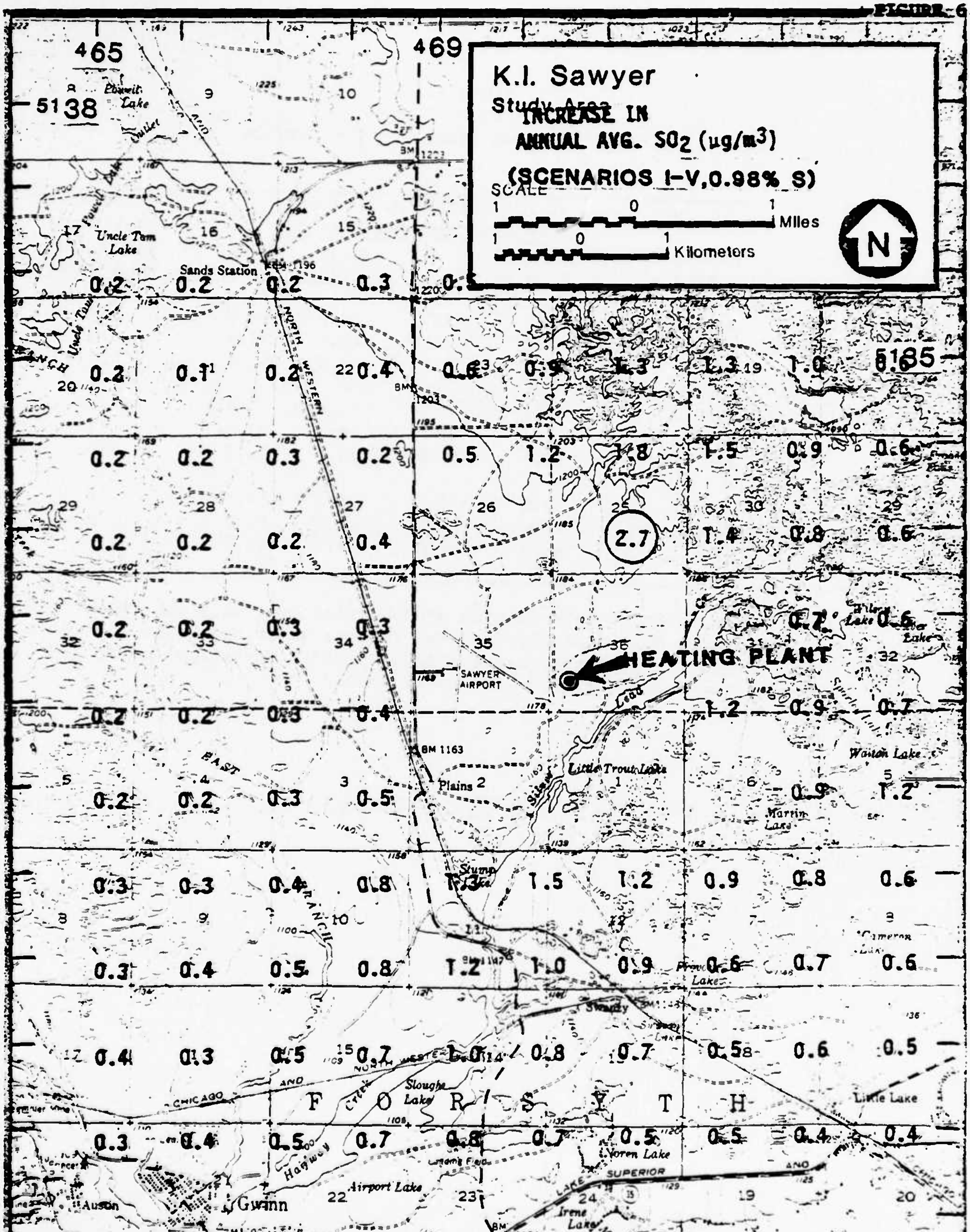
TABLE 6.4

MAXIMUM[a] SO_2 PSD INCREMENT CONSUMPTION

Scenarios	Averaging Time	SO_2 Increment Consumed (micrograms/cubic meter) 0.8% S	0.98% S	1.3% S	1.7% S	SO_2 Increment Available (micrograms/cubic meter)
I-V	Annual	1.7	2.7	4.4	6.5	16
	24-hr	18.3	26.5	41.1	56.4	73
	3-hr	34.8	57.9	98.6	150.0	410
VI-VIII	Annual	2.7	3.7	5.4	7.5	16
	24-hr	25.4	33.6	48.2	63.5	73
	3-hr	61.1	84.2	125.1	176.3	410
IX	Annual	3.8	4.7	6.2	8.2	16
	24-hr	38.0	46.5	61.7	80.7	73
	3-hr	98.0	120.0	159.2	208.2	410

[a] Since maximum impact is predicted when burning coal only and operating the boilers at full capacity, maximum impacts under Scenarios I through V are the same. Similarly maximum impacts under Scenarios VI-VII are the same for a given sulfur content of coal.

FIGURE 6.7



K.I. Sawyer
Study Area
INCREASE IN
ANNUAL AVG. SO_2 (ug/m3)
(SCENARIOS I-V, 0.98% S)
SCALE
Miles
Kilometers
N
HEATING PLANT
2.7
SAWYER AIRPORT
Sands Station
Uncle Tam Lake
Little Trout Lake
Plains
Walton Lake
Martin Lake
Stump Lake
Swanzy
Slough Lake
Little Lake
Voren Lake
Airport Lake
Gwinn
Auson
New Swanzy
Blue Lake
Irene Lake
Dollar Lake
Johnson Lake
F O R S Y T H
CHICAGO AND NORTH WESTERN
LAKE SUPERIOR AND

FIGURE 6.8

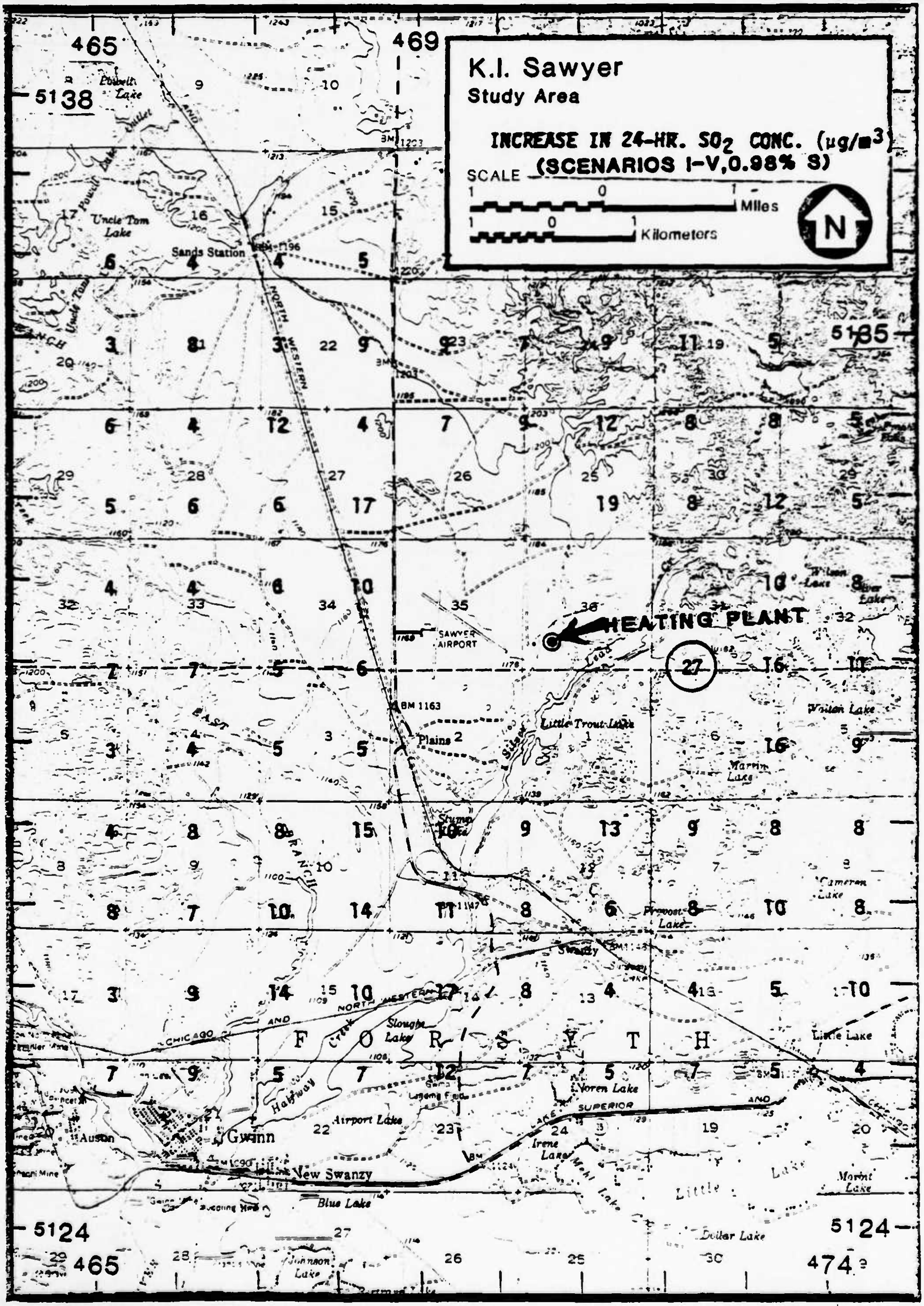
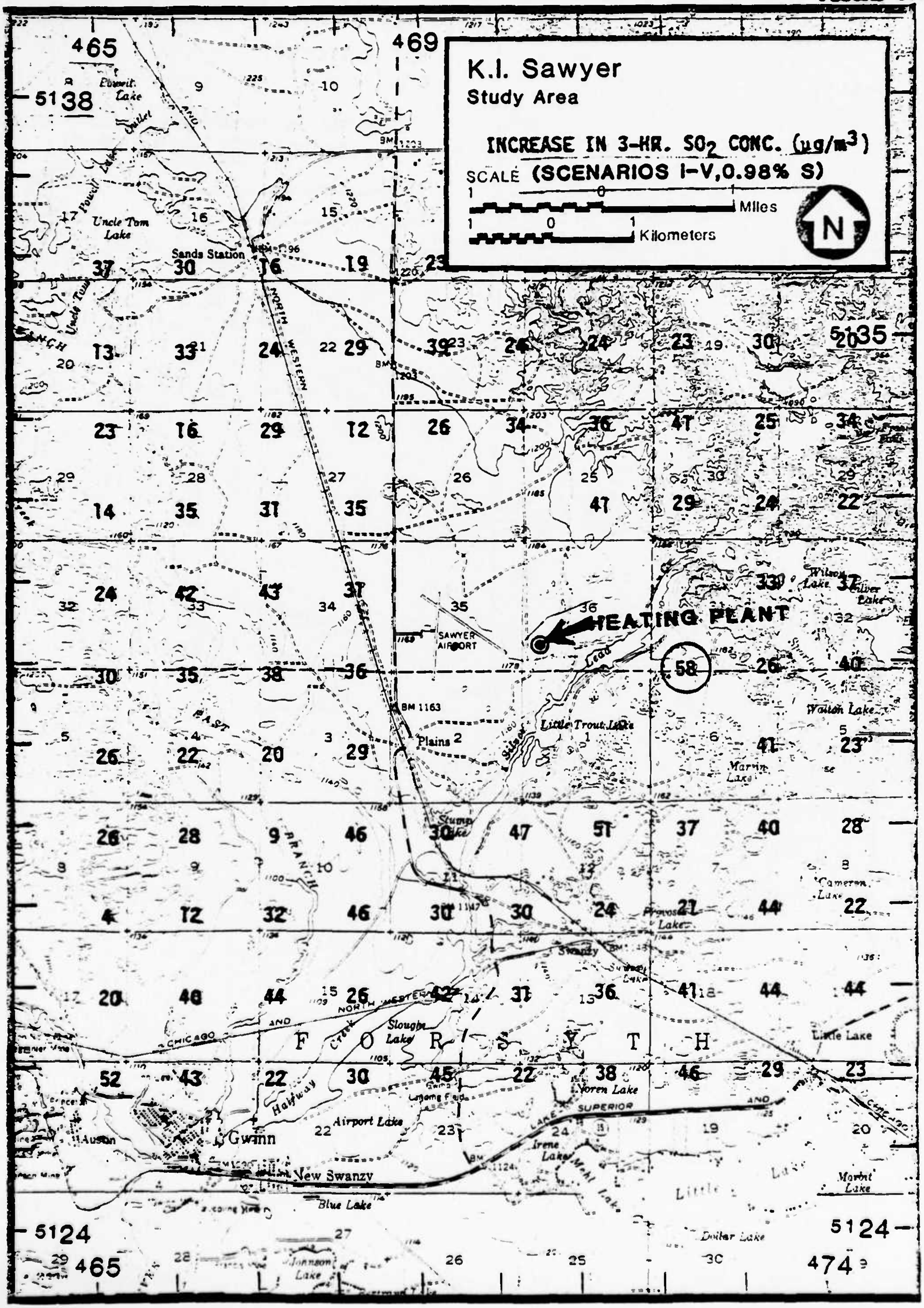

K.I. Sawyer
Study Area
INCREASE IN 24-HR. SO_2 CONC. (µg/m³)
(SCENARIOS I-V, 0.98% S)
SCALE
1 0 1 Miles
1 0 1 Kilometers
N
HEATING PLANT
SAWYER AIRPORT
Sands Station
Uncle Tom Lake
Little Trout Lake
Plains
Gwinn
New Swanzy
Airport Lake
Blue Lake
Voren Lake
Irene Lake
Little Lake
Dollar Lake
F O R S Y T H
465
469
474
5138
5135
5124

FIGURE 6.9


K.I. Sawyer
Study Area
INCREASE IN 3-HR. SO_2 CONC. (µg/m³)
(SCENARIOS I-V, 0.98% S)
SCALE
Miles
Kilometers
N
HEATING PLANT
SAWYER AIRPORT
Sands Station
Plains
Little Trout Lake
Gwinn
New Swanzy
Airport Lake
Blue Lake
Little Lake
Uncle Tom Lake
Wilson Lake
Walton Lake
F O R S Y T H

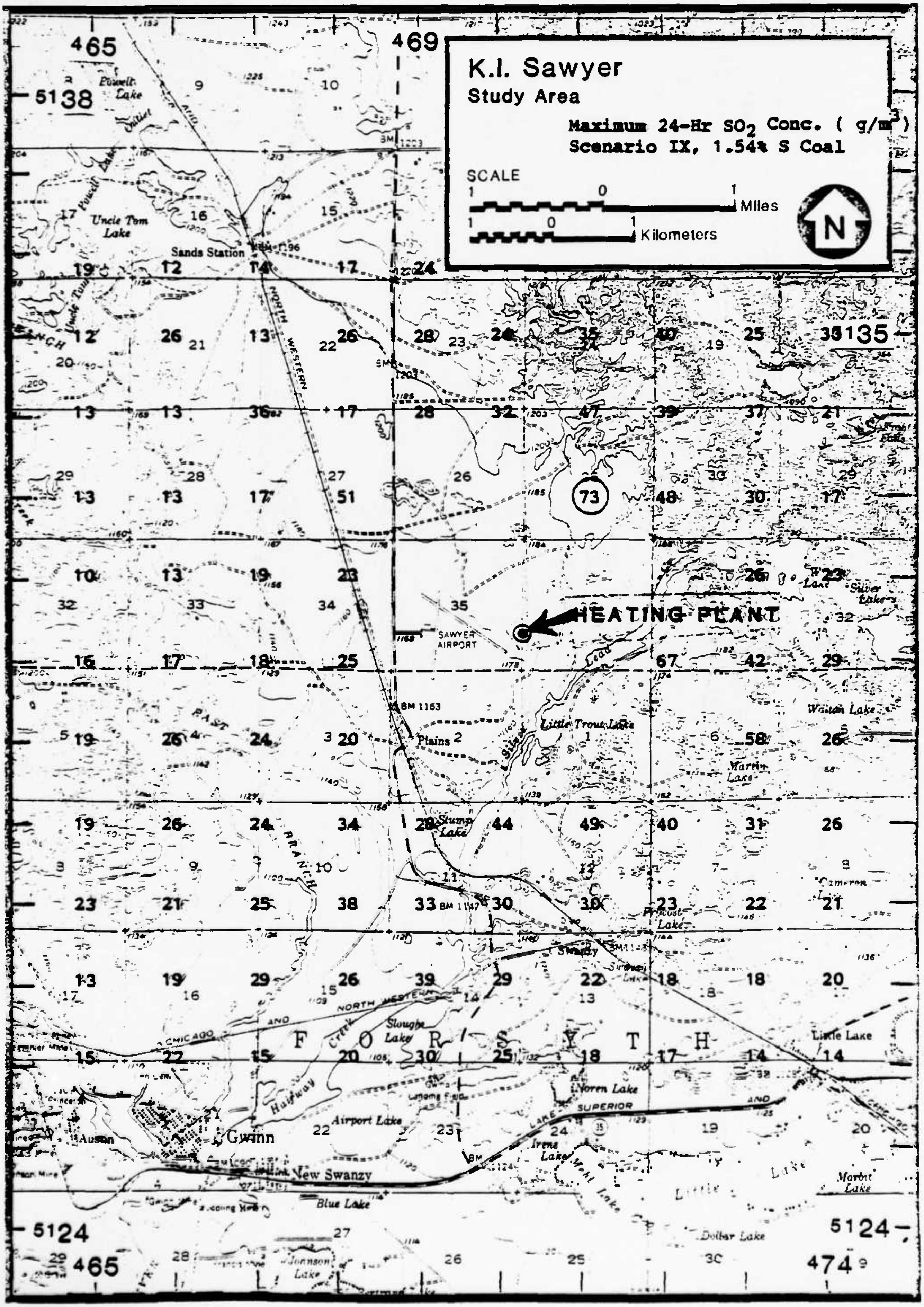

K.I. Sawyer
Study Area
Maximum 24-Hr SO_2 Conc. (g/m^3)
Scenario IX, 1.54% S Coal
SCALE
1 0 1 Miles
1 0 1 Kilometers
N
HEATING PLANT
SAWYER AIRPORT
Sands Station
Uncle Tom Lake
Powell Lake
Little Trout Lake
Plains
Gwinn
New Swanzy
Airport Lake
Blue Lake
F O R S Y T H

TABLE 6.5

PROJECTED AMBIENT AIR QUALITY WHEN BURNING 0.98% S COAL

Pollutant	Averaging Time	Baseline[a] ($\mu g/m^3$)	Predicted Impact[b] ($\mu g/m^3$) Scenarios I-V	Scenarios VI-VIII	Scenario IX	Projected Air Quality[c] ($\mu g/m^3$) I-V	VI-VIII	IX	NAAQS ($\mu g/m^3$)
TSP	Annual	15	0.2	0.3	0.4	15.2	15.3	15.4	75
	24-hr	86	2.2	2.8	3.7	88.2	88.8	89.7	150
SO_2	Annual	4	2.7	3.7	4.7	6.7	7.7	8.7	80
	24-hr	79	26.5	33.6	46.5	105.5	112.6	125.5	365
	3-hr	262	57.9	84.2	120.0	319.9	346.2	382.0	1300
CO	1-hr	6,800	2.9	4.5	6.0	6,803	6,805	6,806	40,000
	8-hr	5,500	0.80	1.80	2.80	5,501	5,502	5,503	10,000
NO_x	Annual	21	0.19	0.59	1.09	21.2	21.6	22.1	100
Ozone[d]	1-hr	196	--	--	--	--	--	--	235

a From Table 4.2
b From Table 6.4 for sulfur content of 0.98%.
c Sum of a and b above.
d No estimate of the source's impact upon ozone levels is possible because there is no recognized model for predicting ozone concentration resulting from a single source's emissions.

air quality in the area was established based on ambient air quality data available for the area. In Table 6.5, the existing and projected air quality concentrations are compared with the NAAQS for different scenarios.

IMPACT ON CLASS I AREA

The Clean Air Act Amendments of 1977 require that the air quality resources in the nation's park and wilderness areas be preserved. As a result, national parks and wilderness areas of certain sizes were designated Class I areas. The 1977 Amendments established specific PSD increments for these areas which are much more restrictive than those for Class II areas. The nearest Class I area is 86 kilometers east of the Base. Maximum impact on this area is given in Table 6.6. The results indicate that the impacts on SO_2 concentrations will be well below the available PSD increments.

ADDITIONAL EMISSION SCENARIOS

In addition to the nine scenarios described earlier in Chapter 3 and their impacts evaluated earlier in this chapter, a few other scenarios were also analyzed. These are sequentially numbered and are described below.

X Consumption of all PSD Increments

Analysis for this scenario indicates that the 24-hour PSD increment consumption is the critical factor. In order to consume the maximum available (73 g/m^3) PSD increment, the SO_2 emissions must be approximately 3.7 tons per day. Considering Scenario IX, operating the new boilers at full load 24-hours a day could burn 126 tons of coal. This amount of coal has to have 1.54% sulfur in order to emit 3.7 tons per day of SO_2.

XI Consumption of 50% of PSD Increments

In order to consume 50% of the maximum allowable PSD increments, it was estimated that SO_2 emissions would have to be 1.85 tons per day under Scenario IX. By using reasoning similar to one in scenario X, the sulfur content of coal has to be at least 0.77%.

XII Violation of Ambient Air Quality Standards

For violation of the air quality standard, it was determined that the 24-hour standard would be violated before other standards are violated. For Scenario IX, SO_2 emissions have to be 14.5 tons per day which is possible only with 6% sulfur coal.

XIII One Stack Vs. Two Stacks

For all the scenarios analyzed it was assumed that each boiler will be equipped with its own stack. If the two new boilers exhaust through the same stack, flow rates will be the sum of the two. This will result in higher plume rise and lower concentrations. The comparison is as given below.

TABLE 6.6

IMPACT ON SENEY NWA, MI[a]

	Maximum SO_2 Concentration ($\mu g/m^3$)
Annual	<0.1
24-Hour Max.	0.8
3-Hour Max.	6.1

[a] Seney National Wilderness Area is the closest PSD Class I area.

	Two Stacks	One Stack
Maximum Annual Average	5.2 $\mu g/m^3$	4.5 $\mu g/m^3$
24-Hour Maximum	49.4 $\mu g/m^3$	39.0 $\mu g/m^3$
3-Hour Maximum	125.5 $\mu g/m^3$	108.5 $\mu g/m^3$

Other data used for this analysis were based on burning 0.98% sulfur coal in one of the new boilers and boilers #5 and 6 at full load.

XIV Tall vs Short Stack Height

In most of the scenarios analyzed, a stack height of 80 feet was used for the new boilers. For this scenario, analysis was performed with a stack height of 155 feet for the new boilers. The results are compared below:

	SO_2 Impact ($\mu g/m^3$)	
	80' stacks	155' stacks
Annual Avg.	5.2	4.1
24-hr. Max.	49.4	40.0
3-hr. Max.	125.5	84.0

Obviously, a taller stack results in lower concentrations.

XV A 5% Increase from Recommended Strategy

For the purposes of this analysis, Scenario IX with 1.0% sulfur coal was considered as the recommended strategy. This was based on the following reasons:

1. No restrictions on the amount of coal usage or hour of operation.
2. No exceedance of PSD increments.
3. No violation of ambient air quality standards.
4. Demonstration of 1.0% sulfur coal as BACT.
5. Banking of emissions from existing boilers (when decommisioned or put on standby) for future expansion.

The fuel consumption in the new boilers were estimated to be 5.2 tons of coal per day. With 1.0% sulfur, this will result in SO_2 emissions of 2.37 tons per day. Impacts of SO_2 emissions at this level and 5% increase from this level are given below.

	SO_2 Impact ($\mu g/m^3$)	
	Recommended Strategy	5% Increase from Recommended Strategy
Annual	4.8	5.0
24-hour Max.	47.5	49.8
3-hour Max.	122.4	128.0

This scenario will be subject to PSD review for SO_2, but will not exceed the available PSD increments.

XVI A 10% Increase from Recommended Strategy

This is similar to Scenario XV except that a 10% increase in fuel was assumed. SO_2 emissions will be 4.1 tons per day. The resulting air quality impacts are estimated to be as given below.

	SO_2 Impact (g/m^3)	
	Recommended Strategy	10% Increase from Recommended Strategy
Annual	4.8	5.3
24-hour Max.	47.5	52.3
3-hour Max.	122.4	134.6

This scenario will be subject to PSD review for SO_2 but will not exceed available PSD increments.

DOWNWASH ANALYSIS

An air quality analysis was performed of potential downwash associated with the new boilers. The GEP stack height was determined to be 155 feet. For stack heights less than 155 feet, a downwash analysis is required. For this analysis stack heights of 80 and 100 feet were assumed.

There are several methods to analyse the impacts under downwash and aerodynamic effects. Initially, a screening analysis is used to determine whether any potential for such impact exists. This is normally done by comparing the stack exit gas velocity with the wind velocity. If the exit gas velocity is greater than 1.5 times the wind velocity, then it is unlikely that downwash would occur.

The exit velocity from the new boilers at rated capacity will be about 29 feet per second. For downwash to occur, the wind velocity must be at least 20 ft/sec (6.1 m/sec). A wind speed of 6.1 m/sec was assumed in the analysis.

EPA's Huber-Snyder Model as incorporated into the Industrial Source Complex Model was used in the analysis. No adjustment was made to the stack heights. Huber calculates the dispersion under neutral stability as follows:

$$_z = 0.7 h_b + 0.067 (x - 3h_b)$$

where: $_z$ = the neutral dispersion vertical coefficient at the property line
h_b = building height
x = downwind distance

The nearest property line is 2000 feet (610 meters). At this distance, σ_z was determined to be 50 meters. The concentration was calculated using the Huber-Snyder Model:

$$X \text{ (1-hour)} = \frac{Q}{\pi \sigma y \ \sigma z \ \ u} \ \exp \frac{-1}{2} \left(\frac{H}{\sigma_z}\right)^2$$

where: Q = emission rate
σy = horizontal dispersion coefficient
H = stack height

The emission rate was assumed to be that at the maximum operating level, 38.9 gm/sec (computed from burning 1.54% sulfur coal at full load in new boilers). At the distance of 610 meters, y is 39 meters under neutral conditions. The calculated concentrations are given in Table 6.7 for two stack heights (80 and 100 feet). A 155 ft stack will meet GEP stack height criterion and would not require a downwash analysis. According to Turner, this concentration is valid for 10 minute averaging time. Using the power law relation suggested by Turner, the 3-hour concentrations were computed. The 24-hour concentration was obtained by dividing the 3-hour concentration by 8 assuming that downwash conditions do not occur during other times of the day. Credits due to emissions from boilers to be decommissioned were not included in this analysis.

IMPACT UPON SOIL AND VEGETATION

The secondary NAAQS are primarily designated to protect the public welfare as opposed to the primary NAAQS designated to protect public health. Protection of the public welfare includes the prevention of vegetation damage and harmful effects to the soil. The secondary NAAQS will not be violated by any of the emissions from the proposed new boilers at KI Sawyer AFB.

The pollutant with the greatest potential for causing vegetation damage is sulfur dioxide. The highest 3-hour SO_2 concentration after the expansion will be well below secondary standard. At this concentration, no vegetation damage is expected.

TSP emissions from the boilers will not cause any violation of the secondary NAAQS. Minute quantities of trace metals may be present, but any effect of these on the soil would be negligible.

SECONDARY IMPACTS

PSD regulations promulgated on August 7, 1980, require that the impacts of secondary emissions be evaluated. The secondary emissions are emissions not directly coming from the source, but are indirectly associated with the construction and/or operation of a major source or major modification. These emissions are an outcome of the growth projected in the area that would occur as a result of the proposed source.

The source under consideration is a modification of the existing heating plant. The proposed changes is not anticipated to cause any additional growth. Most of the employees will come out of the existing labor force.

TABLE 6.7

DOWNWASH ANALYSIS RESULTS[a]

	SO_2 Concentration ($\mu g/m^3$)			
	80 ft stack		100 ft. stack	
Scenario	3-hour	24-hour	3-hour	24-hour
Full Capacity Operation	560	70	531	66

[a] Downwash from the new boilers only was considered. No credits for existing boilers were used.

APPENDIX A

APPLICABLE MICHIGAN AIR POLLUTION CONTROL RULES

ACT 250 of 1965, AS AMENDED

(Tax Exemption Act)

ACT 348 of 1965, AS AMENDED

(Air Pollution Act)

and ADMINISTRATIVE RULES

FOR

AIR POLLUTION CONTROL

STATE OF MICHIGAN

DEPARTMENT OF NATURAL RESOURCES

(b) Operation of the equipment for which the permit is sought will interfere with the attainment or maintenance of the air quality standard for any air contaminant.

(c) The equipment for which the permit is sought will violate the provisions of the clean air act, as amended, 42 U.S.C. § 7401 et seq., and particularly the rules promulgated on and before September 1, 1978, in standards of performance for new stationary sources, 40 C.F.R. §60.1 to §60.275 (July 1, 1978), and national emission standards for hazardous air pollutants, 40 C.F.R. §61.01 to §61.55 (July 1, 1978).

(d) Sufficient information has not been submitted by the applicant to enable the commission to make reasonable judgments as required by subdivisions (a) to (c).

(e) Adequate requested information for preparation of an environmental impact statement is not submitted.

(f) A satisfactory plan for reduction of emissions during air pollution alerts, warnings, and emergencies, as required by rule 203, is not submitted.

(2) When an application is denied, the applicant shall be notified in writing of the reasons therefor. A denial shall be without prejudice to the applicant's right to a hearing before the commission or for filing a further application after revisions are made to meet objections specified as reasons for the denial.

R 336.1208. Permits to operate.

Rule 208. (1) Before the commission issues a permit to operate and except as otherwise provided in subrule (4) of rule 201, a person shall not operate a process, fuel-burning or refuse-burning equipment, or an air-cleaning device pertaining thereto which may be a source of an air contaminant.

(2) Not more than 30 days after completion of the installation, construction, reconstruction, relocation, or alteration of a process, fuel-burning or refuse-burning equipment, or an air-cleaning device pertaining thereto which may be a source of an air contaminant, the owner or his authorized agent of the process or device shall apply in writing to the commission for a permit to operate. Completion of the installation, construction, reconstruction, relocation, or alteration is deemed to occur not later than commencement of a trial operation pursuant to subrule (4) of rule 201.

(3) The commission shall issue the permit to operate equipment if, in the judgment of the commission, all of the following conditions are met:

(a) The equipment operates in compliance with the rules of the commission, the clean air act, as amended, 42 U.S.C. §7401 et seq., and the rules promulgated on and before September 1, 1978, in standards of performance for new stationary sources, 40 C.F.R. §60.1 to §60.275 (July 1, 1978), and national emission standards for hazardous air pollutants, 40 C.F.R. §61.01 to §61.55 (July 1, 1978).

(b) The equipment does not interfere with the attainment or maintenance of the air quality standard for any air contaminant.

(c) The equipment is completed in compliance with the permit to install and conditions attached to the permit to install.

(4) The permit to operate continues in effect as long as the equipment performs in accordance with the conditions upon which the permit is based. The commission, at any time after notice and opportunity for a hearing, may rescind its permit to operate and the equipment shall not be operated if evidence indicates that the equipment is not performing in accordance with the conditions upon which the permit is based.

<u>R 336.1220. Construction of sources of volatile organic compounds in ozone non-attainment areas; conditions for approval.</u>

<u>Rule 220.</u> Unless the following conditions are met, the commission shall deny a permit to install for a major offset source of volatile organic compounds proposed for location within an ozone nonattainment area:

(a) The proposed equipment shall comply with the lowest achievable emission rate for volatile organic compounds.

(b) All existing sources in the state owned or controlled by the owner or operator of the proposed source shall be in compliance with all applicable local, state, and federal air quality regulations or shall be in compliance with a consent order or other legally enforceable agreement specifying a schedule and timetable for compliance.

(c) Prior to start-up of the proposed equipment, a reduction (offset) of the total hourly and annual volatile organic compound emissions from existing sources equal to 110% of allowed emissions for the proposed equipment shall be provided. The emission offset for a source locating in Wayne, Oakland, Macomb, St. Clair, Washtenaw, Livingston, and Monroe counties shall be secured from sources in those counties. The emission offset for a source locating in any other ozone nonattainment county may be secured from any ozone nonattainment county in Michigan, except Wayne, Oakland, Macomb, St. Clair, Washtenaw, Livingston, and Monroe counties.

(d) Subdivisions (a) and (c) do not apply if the allowable emission rates for the proposed equipment are less than 50 tons per year, 1,000 pounds per day, and 100 pounds per hour.

R 336.1221 Construction of sources of particulate matter, sulfur dioxide, or carbon monoxide in or near nonattainment areas; conditions for approval.

Rule 221. Unless the following conditions are met, the commission shall deny a permit to install for a major offset source of particulate matter, sulfur dioxide, or carbon monoxide if such source may exacerbate an existing violation of any air quality standard or if such source is proposed for location in a nonattainment area:

(a) The proposed equipment shall comply with the lowest achievable emission rate for the pollutant for which the area is nonattainment.

(b) All existing sources in the state owned or controlled by the owner or operator of the proposed source shall be in compliance with all applicable local, state, and federal air quality regulations or shall be in compliance with a consent order or other legally enforceable agreement specifying a schedule and timetable for compliance.

(c) Prior to start-up of the proposed equipment, an emission reduction (offset) from existing sources in the area of the proposed source shall be provided such that, in the commission's judgment, there is a net air quality benefit and reasonable progress toward attainment of the applicable air quality standard. Such offsets shall be on a time frame compatible with the applicable air quality standard. If the proposed equipment is to be located in an area not meeting the applicable health-related air quality standard, the emission reduction shall be not less than 1.2 to 1. If the proposed equipment is to be located in an area not meeting the welfare-related air quality standard, the emission reduction shall be more than 1 for 1. If the offsetting emissions involve the control of fugitive particulate emissions, the emission reduction shall be not less than 1.5 to 1.

(d) The requirements of subdivision (a) of this rule do not apply to particulate, sulfur dioxide, and carbon monoxide emissions if the increased allowable emissions are less than 50 tons per year and 1,000 pounds per day.

(e) The requirements of subdivision (c) of this rule do not apply to particulate and sulfur dioxide emissions if the increased allowable emissions are less than 50 tons per year and 1,000 pounds per day.

(f) The requirements of subdivision (c) of this rule do not apply to carbon monoxide emissions.

R 336.1240. Required air quality models.

Rule 240. (1) All air quality modeling demonstrations required by the commission or used to support or amend the state implementation plan shall be made using 1 of the following models:

(a) An applicable model cited in the United States environmental protection agency's "Guideline on Air Quality Models", OAQPS, 1.2-080, April 1978.

MICHIGAN AIR POLLUTION CONTROL COMMISSION

GENERAL RULES

As Amended February 17, 1981

PART 3. EMISSION LIMITATIONS AND PROHIBITIONS—PARTICULATE MATTER

R 336.1301. Standards for density of emissions.

Rule 301. (1) A person shall not cause or permit to be discharged into the atmosphere, from a single source of emission, a visible air contaminant with a density of more than 20% opacity, except in the following situations:

(a) A visible air contaminant with a density of not more than 40% opacity may be emitted for not more than 3 minutes in any 60-minute period, but this emission shall not be permitted on more than 3 occasions during any 24-hour period.

(b) Where the presence of uncombined water vapor is the only reason for failure of an emission to meet the requirements of this rule.

(c) Where specifically permitted by the commission in a case where compliance is not technically and economically feasible and where all other requirements of the commission's rules are being met.

(2) The provisions of this rule shall not apply to visible emissions from slot-type coke ovens.

R 336.1302. Points of measuring density.

Rule 302. The density of an air contaminant emission shall be measured at the point of maximum opacity not influenced by the presence of uncombined water.

R 336.1303. Grading visible emissions.

Rule 303. Opacity of a visible emission of an air contaminant shall be graded by certified observers using a technique approved by, and on file with, the commisison. Certification of observers shall be by procedures approved by, and on file with, the commission.

R 336.1310. Open burning.

Rule 310. (1) A person shall not cause or permit open burning of refuse, garbage, or any other waste materials, except for the burning of the following:

(a) Waste disposal of material from and at 1- or 2-family dwellings where the burning does not violate any other commission rules.

(b) Structures and other materials used exclusively for fire prevention training if prior approval is obtained from the commission.

(c) Trees, logs, brush, and stumps in accordance with applicable state and local regulations if the burning is not conducted within a priority I area as listed in table 33, a priority II area as listed in table 34, nor closer than 1400 feet to an incorporated city or village limit and the burning does not violate any other commission rules.

(d) Beekeeping equipment and products, including frames, hive bodies, hive covers, combs, wax, and honey when burned for bee disease control.

(e) Logs, brush, charcoal, and similar materials for the purpose of food preparation or recreation.

(2) These exceptions do not authorize open burning where prohibited by local law or regulation.

R 336.1320. Compliance programs.

Rule 320. (1) A person responsible for the operation of any existing source subject to the provisions of rule 331, table 31, items A.3, A.4, B.5, G.2, I, and J shall submit to

the Commission, within 1 year after the effective date of such rule, a written program, acceptable to the commission, for compliance with such rule or evidence of compliance with such rule. Such evidence shall include available emission data, material balance calculations, control equipment specifications, or other information that demonstrates compliance.

(2) The program required by subrule (1) shall include the method by which compliance with such rule shall be achieved, a description of new equipment to be installed or modifications to existing equipment to be made, and a timetable which specifies, at a minimum, the following dates:

(a) The date equipment shall be ordered.

(b) The date construction or modification of equipment shall begin.

(c) The date initial start-up of equipment shall begin.

(d) The date final compliance shall be achieved, if not the same as the date specified in subdivision (c).

R 336.1330. Electrostatic precipitator control systems; where required.

Rule 330. (1) After July 1, 1980, it shall be unlawful to operate any cement kiln, kraft recovery boiler, lime kiln, calciner, pulverized coal-fired boiler, basic oxygen furnace, or gypsum dryer controlled by an electrostatic precipitator control system unless each transformer-rectifier set of the electrostatic precipitator is equipped with a saturable core reactor, silicon-controlled rectifier linear reactor, or equivalent type automatic control system approved by the commission. Each automatic controller shall be set to provide maximum power, or optimal power if operating in a sparking mode, from its respective transformer-rectifier set.

(2) Each transformer-rectifier set subject to the provisions of subrule (1) shall be capable of operating in a spark-limited mode and shall meter and display the primary RMS voltage and amperage, the average secondary amperage, and the average spark rate. The requirement to meter and display the average spark rate shall not apply if the automatic controller employs solid state circuitry to preset power levels based on sparking rate limits.

(3) The commission shall waive the requirements of subrule (2) if both of the following conditions are met:

(a) A satisfactory demonstration is made that the precipitator is capable of providing for compliance with all applicable particulate emission and opacity limits.

(b) The precipitator existed before July 1, 1979, or was covered by an application for a permit to install received by the commission prior to July 1, 1979.

R 336.1331. Emission of particulate matter.

Rule 331. (1) It is unlawful for a person to cause or allow the emission of particulate matter from any source in excess of any of the following limits:

(a) The maximum allowable emission rate listed in table 31.

(b) The maximum allowable emission rate listed by the commission on its own initiative or by application. A new listed value shall be based upon the control results achievable with the application of the best technically feasible, practical equipment available. This applies only to sources not assigned a specific emission limit in table 31.

(c) The maximum allowable emission rate specified as a condition of a permit to install or a permit to operate.

(d) The maximum allowable emission rate specified in a voluntary agreement, performance contract, stipulation, or an order of the commission.

(e) The maximum allowable emission rate as determined by table 32 for sources not covered in subdivisions (a) to (d).

(2) Compliance with any emission limit specified in this rule shall be determined by using the corresponding reference test method specified in table 31.

- at 50% excess

TABLE 31

Particulate matter emission schedule

Source	Capacity rating for each unit	Maximum allowable emission at operating conditions[a] (lbs. particualte per 1,000 lbs. gas except as noted)	Applicable reference test method
A. Fuel burning equipment			
1. Pulverized coal (includes cyclone furnaces)	0-1,000,000 lbs. steam per hour.	See figure 31 for maximum emission limit.	5B or 5C
	Over 1,000,000 lbs. steam per hour.	Apply to commisison for specific emission limit.	
2. Other modes of firing coal (other than pulverized)	0-100,000 lbs. steam per hour.	0.65 until superseded by A.3 and A.4.	5B or 5C
	100,000-300,000 lbs. steam per hour.	0.65 - 0.45[b]	
	Over 300,000 lbs. steam per hour.	Apply to commission for specific emission limit.	
3. Other modes of firing coal (other than pulverized) Existing fuel-burning equipment that is in a single structure which has a combined coal-fired existing capacity less than 250,000,000 Btu per hour.	0-20,000,000 Btu per hour input.	0.65 effective immediately.	5B or 5C
	20,000,001-100,000,000 Btu per hour input.	0.45 compliance shall be achieved as expeditiously as practical, but not later than July 1, 1981.	5B or 5C
	Over 100,000,000 Btu per hour input.	0.30 compliance shall be achieved as expeditiously as practical, but not later than December 31, 1982.	5B or 5C
4. Other modes of firing coal (other than pulverized) Existing fuel-burning equipment that is in a single structure which has a combined existing capacity equal to or greater than 250,000,000 Btu per hour.	All sizes	0.30 compliance shall be achieved as expeditiously as practical, but not later than December 31, 1982.	5B or 5C
5. Other modes of firing coal (new sources)[f]	All sizes	0.10	5B or 5C
6. Wood (sawdust, shavings, hogged, other) where heat input of wood fuel 75% of total heat input		0.50	5B or 5C
All other combination fuel-burning equipment that uses wood as 1 of the fuels.		Apply to commission for specific emission limit.	
7. Combination fuel-firing or combination fuel/waste-firing (new sources)[f]	All sizes	Apply to commission for specific emission limit.	5B or 5C
B. Incinerators	Rating in lbs. waste per hour		
1. Residential apartments, commercial and industrial[c](d)	0-100	0.65	5B or 5C
	Over 100	0.30	5B or 5C
2. Municipal	All	0.30	5B or 5C
3. Pathological (d)		0.20	5A, 5B or 5C
4. Manure drying or incineration[d]		0.20	5A, 5B or 5C
5. Liquid waste incinerator		0.10 compliance shall be achieved as expeditiously as practical, but not later than December 31, 1982.	5B or 5C
6. Sewage sludge incinerator		0.20 compliance shall be achieved as expeditiously as practical, but not later than December 31, 1982.	5B or 5C
C. Steel manufacturing			
1. Open hearth furnaces		0.10	5B or 5C
2. Basic oxygen furnaces		0.10	5B or 5C
3. Electric furnaces		0.10	5B or 5C
4. Sintering plants		0.20	5B or 5C
5. Blast furnaces		0.15	5B or 5C
6. Heating and reheating furnaces		0.30	5B or 5C
7. Coke oven coal preheater equipment effective after July 1, 1979		0.45[g]	5B or 5C

Source		Lbs. particulate/1,000 lbs. gas except as noted	Applicable reference test method
D. Ferrous cupola foundry operations	Total plant melt rate in tons/hr.		
1. Existing production cupolas[h]	0-10	0.40	5A, 5B or 5C
	10-20	0.25	5A, 5B or 5C
	over 20	0.15	5A, 5B or 5C
2. Existing jobbing cupolas[h]		0.40	5A, 5B or 5C
3. Electric arc melting		0.10	5A, 5B or 5C
4. Sand handling		0.10	5A, 5B or 5C
5. All new cupolas	0-15	1.8 - 0.7[b](i)	5A, 5B or 5C
	over 15	0.7[i]	
E. Chemical and mineral kilns		0.20	5B or 5C
F. Asphalt paving plants			
1. Located within a priority I or II area (before January 1, 1980)		0.30	5A, 5B or 5C
2. Located within a priority I or II area (after January 1, 1980)		0.10	5A, 5B or 5C
3. Located outside priority I and II areas		0.30	5A, 5B or 5C
G. Cement manufacture			
(Up to 15,000 barrels per day kiln capacity)			
1. Kiln - wet or dry process		0.25	5B or 5C
2. Clinker coolers (before January 1, 1981)		0.30	5B or 5C
(after January 1, 1981)		0.10	5B or 5C
3. Grinding, crushing, and other material handling		0.15	5B or 5C

Note: A maximum allowable emission listing shall be applied for to the commission for all kiln installations which will result in a total plant kiln capacity in excess of 15,000 barrels of cement per day.

Source	Gas flow rate (SCFM)	Lbs. particulate/1,000 lbs. gas except as noted	Applicable reference test method
H. Iron ore pelletizing			
Grate kilns and traveling grates	Greater than 600,000	Apply to commission for specific emission limit.	
	300,000 to 600,000	0.10	5A, 5B or 5C
	100,000 to 300,000	0.15	5A, 5B or 5C
	less than 100,000	0.20	5A, 5B or 5C
I. Fertilizer plants (includes ammoniator, granulator, reactor, dryer, cooler blender and all other processes) Compliance shall be achieved as expeditiously as practical, but not later than January 1, 1981.		0.10	5A, 5B or 5C
J. Exhaust systems serving material handling equipment not otherwise listed in table 31 Compliance shall be achieved as expeditiously as practical, but not later than July 1, 1981.		0.10	5A, 5B or 5C

Notes:

(a) Fuel burning and incineration limitation shall be calculated to 50% excess air.

(b) Emission limitations for specific ratings are determined by linear interpolation between the ranges shown.

(c) These emission limitations do not apply to domestic incinerators (defined as having not more than 5 cubic feet of storage capacity).

(d) Afterburner or approved equivalent is mandatory.

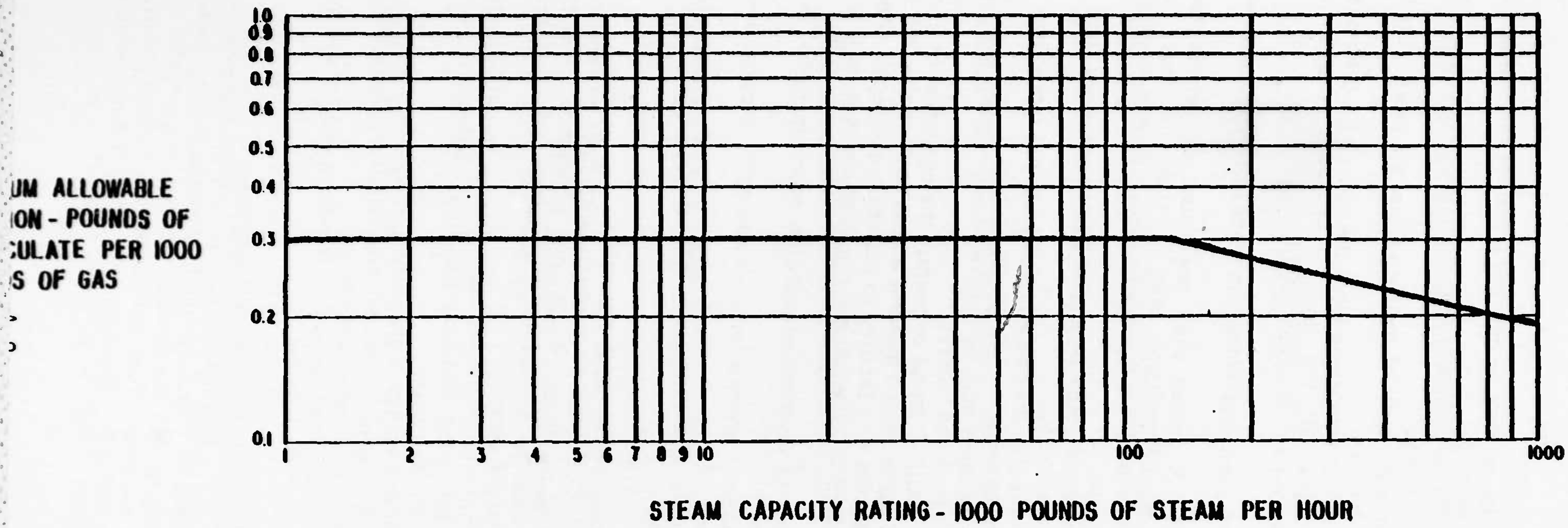
(e) Differentiation between jobbing and production foundries.
Cupolas used in a jobbing foundry are the same as those used in a production foundry and vary in size only according to the quantity of iron melted per hour.
However, the cupolas in a jobbing foundry are run intermittently just long enough at one time to pour the molds that are ready on the foundry floor, job by job. This might be for a 2- to 4-hour period per day for any number of days per week.
Production foundry cupolas melt continuously to pour a succession of molds that are constantly being prepared to reserve this continuous flow of iron. This could become 8 hours, 16 hours, or 24 hours per day for any number of days per week.

(f) New sources are defined as those for which the permit to install was issued after the effective date of these rules.

(g) Pounds particulate/ton of coal fed to the coal preheater.

(h) Any existing cupolas are considered to be in compliance with table 31 of rule 331 if they meet the particulate emission limit for new cupolas.

FIGURE 31



Note: It is required that a maximum allowable emission listing be applied for to the air pollution control commission for all pulverized coal (and cyclone) furnaces having capacity ratings in excess of 1 million pounds of steam per hour.

(a) A visible emission may be emitted from not more than 10% of the total pushside doors on the coke battery.
(b) A visible emission may be emitted from not more than 10% of the total cokeside doors on the coke battery.
(c) A visible emission may be emitted from not more than 10% of the total leveling doors on the coke battery.
(2) Visible emissions emanating from the doors of a coke oven that has been pipeline charged within 1 hour of the time of observation shall not be considered when calculating the percentage of doors leaking.

R 336.1357. Coke oven door emissions from slot-type coke ovens; doors that are taller than 5 meters.
Rule 357. (1) A person shall not cause or permit to be discharged into the atmosphere any visible emission from any pushside door, cokeside door, or leveling door serving a coke oven equipped with doors that are taller than 5 meters, with the following exceptions:
(a) A visible emission may be emitted from not more than 12% of the total pushside doors on the coke battery.
(b) A visible emission may be emitted from not more than 12% of the total cokeside doors on the coke battery.
(c) A visible emission may be emitted from not more than 10% percent of the total leveling doors on the coke battery.
(2) A person shall not cause or permit the operation of a coke battery equipped with coke oven doors taller than 5 meters, unless both of the following provisions are met:
(a) There is access to a facility to maintain and repair doors and buckstays.
(b) An inventory of cleaned and repaired doors is maintained to comply with all of the following:
(i) The number of inventoried pushside doors exceeds 5% of the number of pushside doors in service.
(ii) The number of inventoried cokeside doors exceeds 5% of the number of cokeside doors in service.
(iii) The number of inventoried leveling doors exceeds 5% of the number of leveling doors in service.

R 336.1370 Collected air contaminants.
Rule 370. (1) Collected air contaminants shall be removed as necessary to maintain the equipment at the required operating efficiency. The collection and disposal of air contaminants shall be performed in a manner so as to minimize the introduction of contaminants to the outer air.
(2) At a minimum, in priority I and II areas listed in tables 33 and 34, the use of 1 or more of the following material handling methods is required for the transport of collected air contaminants:
(a) Enclosed trucking or transporting vehicles.
(b) Enclosed, pneumatic, or screw conveying transporting equipment.
(c) Water or dust suppressant sprays.
(d) An acceptable method which is equivalent to the methods listed in subdivisions (a), (b), and (c) of this subrule.

R 336.1371 Fugitive dust control programs.
Rule 371. (1) Upon notification by the commission, the person who is responsible for the operation of a facility which processes, uses, stores, transports, or conveys bulk materials, such as, but not limited to, coal, coke, metal ores, limestone, cement, sand, gravel, and material from air pollution control devices or a facility which has activities specifically identified in R 336.1372 and which is located in a priority I or

MICHIGAN AIR POLLUTION CONTROL COMMISSION

GENERAL RULES

Effective Date: January 18, 1980

PART 4. EMISSION LIMITATIONS AND PROHIBITIONS - SULFUR-BEARING COMPOUNDS

R 336.1401. Emission of sulfur dioxide from power plants.

Rule 401. (1) In a power plant, it is unlawful for a person to burn fuel that does not comply with the sulfur content limitation of table 41 or which, when burned, results in sulfur dioxide emissions exceeding an equivalent emission rate as shown in table 42, unless the following conditions are met:

(a) The source of fuel burning is not subject to federal emission standards for new stationary sources.

(b) An installation permit, if required by part 2, was approved by the commission before August 17, 1971.

(c) The user furnishes evidence that the fuel burning does not create, or contribute to, an ambient level of sulfur dioxide in excess of the applicable ambient air quality standards. The evidence shall consist of air quality data or stack dispersion calculations, or both, satisfactory to the commission.

(d) The user is operating in compliance with a voluntary agreement, order, stipulation, or variance from the commission.

(2) Notwithstanding the provisions of subrule (1), an exception from the limitations of table 41 shall not be permitted after January 1, 1980, unless specific authorization is granted by the commission.

(3) A person responsible for operation of a source that, on the effective date of the 1973 amendment to this rule or for any anticipated time in the future, is or will be using fuel with a sulfur content in excess of that allowed to be burned on July 1, 1978, as listed in table 41, or which, on such effective date or any anticipated time in the future, is or will be emitting sulfur dioxide in excess of the equivalent emission for that fuel, as shown in table 42, shall submit to the commission a written program for compliance with this rule within 60 days after such effective date. This requirement does not apply to a source for which the commission has approved an exception to table 41 under the provisions of subrule (1).

(4) The program required by subrule (3) shall include the method by which compliance shall be achieved, a complete description of new equipment to be installed or modifications to existing equipment to be made, and a timetable which specifies, at a minimum, the following dates:

(a) The date equipment shall be ordered.

(b) The date construction or modification of equipment shall begin.

(c) The date initial start-up of equipment shall begin.

(d) The date emissions shall be reduced to levels shown in tables 41 and 42.

(5) The commission may allow any source that is required to submit a compliance program under subrule (3) an extension to the programmed compliance date, if the following conditions are met:

(a) The source of fuel burning is not subject to federal emission standards for new stationary sources.

(b) An installation permit, if required by part 2, was approved by the commission before August 17, 1971.

(c) The user furnishes satisfactory evidence to the commission that the fuel burning does not create or contribute to an ambient level of sulfur dioxide in excess of the applicable ambient air quality standards.

(6) A person shall not cause or permit the burning of fuel in any fuel-burning equipment that results in an average emission of sulfur dioxide for any calendar month at a rate greater than was emitted by that fuel-burning equipment for the corresponding calendar month of the year 1970, unless otherwise authorized by the commission.

(7) The use of fuels having sulfur contents as set forth in this rule shall not allow degradation in the mass rate of particulate emission, unless otherwise authorized by the commission. The commission may require source emission tests which may be performed by, or under the supervision of, the commission at the expense of the owners and may require the submission of reports to the commission both before and after changes are made in the sulfur content in fuel.

TABLE 41

Sulfur in fuel limitations for fuel-burning equipment

Plant capacity[a] 1000 lbs. Steam per hour	Maximum sulfur content in fuel[b] Percent by weight[c] July 1, 1975	July 1, 1978
0-500	2.0	1.5
Over 500	1.5	1.0

TABLE 42. Equivalent emission rates

% Sulfur in fuels[c]	Parts per million by volume Corrected to 50% excess air: Solid fuel[d] (12,000 Btu/lb)	Liquid fuel[e] (18,000 Btu/lb)	Pounds of sulfur dioxide per Million Btu of heat input: Solid fuel[d] (12,000 Btu/lb)	Liquid fuel[e] (18,000 Btu/lb)
1.0	590	420	1.67	1.11
1.5	890	630	2.50	1.67
2.0	1180	840	3.33	2.22

(a) For the purpose of this rule, "plant capacity" is defined as the total steam production capacity of all coal- and oil-burning equipment in a power plant as of August 17, 1971. A "power plant" is defined as a single structure devoted to steam or electric generation, or both, and may contain multiple boilers.

(b) "Maximum sulfur content in fuel" is defined as the average sulfur content in all fuels burned at any one time in a power plant. The sulfur content shall be calculated on the basis of 12,000 Btu per pound for solid fuels and 18,000 Btu per pound for liquid fuels.

(c) The determination of sulfur content (percent by weight) of fuel shall be carried out in accordance with a procedure acceptable to the commission.

(d) Solid fuels include both pulverized coal and all other coal.

(e) Liquid fuels include distillate oil (No. 1 and No. 2), heavy oil (No. 4, No. 5, and No. 6), and crude oil.

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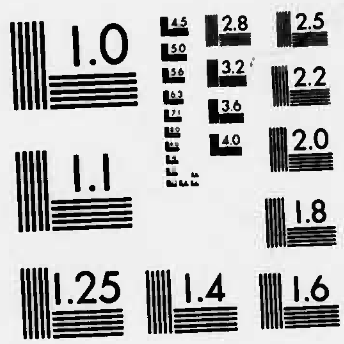


MICROCOPY RESOLUTION TEST CHART
NATIONAL BUREAU OF STANDARDS-1963-A

R 336.1402. Emission of sulfur dioxide from fuel-burning sources other than power plants.

Rule 402. (1) Except as provided in rule 401 and subrule (2), after January 1, 1981, it is unlawful for a person to cause or allow the emission of sulfur dioxide from the combustion of any coal or oil fuel in excess of 1.7 pounds per million Btu's of heat input for oil fuel or in excess of 2.4 pounds per million Btu's of heat input for coal fuel.

(2) The provisions of this rule do not apply to a fuel-burning source that is unable to comply with the specified emission limits because of sulfur dioxide emissions caused by the presence of sulfur in other raw materials charged to the fuel-burning source. This exception shall apply if at any time the actual sulfur dioxide emission rate exceeds the expected theoretical sulfur dioxide emission rate from fuel burning. The expected theoretical sulfur dioxide emission rate shall be based on the quantity of fuel burned and the average sulfur content of the fuel.

R 336.1403. Oil and natural gas producing or transporting facilities and natural gas processing facilities; emissions; operation.

Rule 403. (1) Except as provided in subrule (3), it is unlawful for a person to cause or allow the emission of sour gas from an oil or natural gas producing or transporting facility or a natural gas processing facility without burning or equivalent control of hydrogen sulfide and mercaptans.

(2) Except as provided in subrule (3), sour gas that is burned at an oil or natural gas producing or transporting facility or at a natural gas processing facility shall be burned in a smokeless flare, an approved incinerator, or other combustion system with elevated discharge to the atmosphere. The flare, incinerator, or other combustion system shall be equipped with a continuously burning pilot flame and failsafe sensors capable of detecting flame extinguishment, unless otherwise authorized by the commission.

(3) The provisions of subrules (1) and (2) shall not apply to those crude oil producing facilities which serve a well or group of wells which attained an average production level of 10 or less barrels per day per well prior to January 1, 1978, unless the commission has received 1 complaint of odors regarding the facility, and the owner or operator is unable to or fails to demonstrate to the satisfaction of the commission that the uncontrolled hydrogen sulfide and mercaptan emissions do not cause an odor nuisance or health hazard.

(4) A person shall not cause or allow the emission of sulfur dioxide from a new sweetening facility, unless such emissions are controlled using the best available control technology.

(5) The operator of a sour gas, crude, or condensate sweetening facility shall do all of the following:

(a) Monitor the mass flow rate of hydrogen sulfide either entering the plant or going to the waste gas flare or flares on a periodic schedule specified by the commission. The monitoring program shall include a determination of the hydrogen sulfide concentration using colorimetric detector tubes or their equivalent and a determination of the volumetric gas flow rate. The monitoring data shall be submitted to the commission in an acceptable format within 30 days following the end of the month in which the data was collected.

(b) Provide fencing, warning signs, or other measures as necessary to warn or deter unauthorized individuals from entering the plant property or buildings. Signs shall read: "Danger—Poison Gas" with no less than 1 sign on each side of the plant property.

(c) Provide control of malodorous emissions from any pressure relief valve or valves, storage tanks, and dehydrator vent or vents by burning or equivalent control.

(d) Conduct a program of continuous monitoring of concentrations of hydrogen sulfide in any building enclosing a sweetening process. The sensor shall be placed as close to process equipment as practicable. The system shall be designed, installed, and maintained to provide a visual alarm when the hydrogen sulfide concentration exceeds 50 ppm.

(e) Automatically begin a safe and orderly shutdown of all process inflow streams to the facility if the concentration of hydrogen sulfide is more than 100 ppm in any building enclosing a sweetening process. Full operation may be resumed only after successful corrective measures have been applied.

(f) Automatically commence shut-in of the facility within 1 second after extinguishment of the flare flame, unless otherwise authorized by the commission. Operation of the facility shall not continue unless corrective measures taken to reignite the flame are successful.

(6) A new sweetening facility shall not be installed at a distance of less than 1,300 feet from an existing residence, unless otherwise authorized by the commission. Such authorization shall depend upon a satisfactory showing by a permit applicant that an odor nuisance shall not result from a lesser setback distance.

R 336.1404. Emission of sulfuric acid mist from sulfuric acid plants.

Rule 404. After July 1, 1980, it is unlawful for a person to cause or allow the emission of sulfuric acid mist from any sulfuric acid plant in excess of 0.50 pounds per ton of acid produced, the production being expressed as 100% H_2SO_4. Compliance with this limit shall be demonstrated using reference test method 8.

DEPARTMENT OF NATURAL RESOURCES

AIR QUALITY DIVISION

ANNUAL REPORTING AND AIR SURVEILLANCE FEES

Effective Date: January 30, 1980

Filed with the Secretary of State on January 15, 1980
These rules take effect 15 days after filing with the Secretary of State

(By authority conferred on the department of natural resources by sections 5 and 14a of Act No. 348 of the Public Acts of 1965, as amended, and Executive Reorganization Order Nos. 1973-2, 1973-2a, and 1976-1, being §§336.15, 336.24a, and 299.11 of the Michigan Compiled Laws)

R 336.81 — R 336.83. Rescinded by R 336.205.

R 336.201. Definitions.

Rule 1. As used in these rules:

(a) "Commercial location" means a publicly or privately owned place where persons are engaged in the exchange or sale of goods or services. Commercial location also means multiple housing units which have a single owner and which are designed for 3 or more families. Commercial location does not include elementary and secondary schools and facilities owned and operated by the state government. A separate building or group of buildings used for the exchange or sale of goods or services which has a single owner and manager constitutes a separate commercial location.

(b) "Department" means the department of natural resources.

(c) "Geographical site" means contiguous land ownership by 1 landowner. A public right-of-way, such as a road, railroad, and watercourse through part of the site, is not considered to break the continuity. If transmission and fuel delivery rights-of-way or a strip of land that serves no other principal purpose than as a transportation or materials handling link connects 2 or more otherwise separate geographical sites, such connected sites shall be considered separate geographical sites.

(d) "Manufacturing location" means a place where a person is engaged in the making of goods or wares, including the generation of electricity, in the processing of material, or primarily in the disposing or treating of solid or liquid waste. For the purpose of assessing a surveillance fee, manufacturing location includes all such places, whether publicly or privately owned and contained within 1 geographical site, except for places owned and operated by the state government. A power plant, as defined in table 42 of rule 401, constitutes a separate manufacturing location when used to supply steam or energy to more than 1 other manufacturing or commercial location. However, a power plant with a capacity of more than 500,000 pounds of steam per hour is considered a separate manufacturing location. For a large industrial complex or other unusual cases, the department may determine that the complex constitutes more than 1 manufacturing location, based on such factors as separate corporate operating division units or sections.

R 336.202. Annual reports.

Rule 2. The department shall require an annual report from a commercial, industrial, or governmental source of emission of an air contaminant if, in the

judgment of the department, information on the quantity and composition of an air contaminant emitted from the source is considered by the department as necessary for proper management of the air resources. The information shall be specified by the department and shall be submitted on forms available from the department. The information shall include factors deemed necessary by the department to reasonably estimate quantities of air contaminant discharges and their significance. The report shall be submitted to the department not later than November 15 of each year following notification by the department that the report is required. The notification shall be in writing and shall be mailed to the owner or operator of the source of emission not less than 45 days before the deadline for submitting the report.

R 336.203. Annual surveillance fees; calculation.

Rule 3. (1) Except as provided in rule 4, a person who operates an air contaminant source at a commercial or manufacturing location which emits 1 or more of the air contaminants listed in table 141 of rule 4 to the outer air, shall pay to the state of Michigan an annual surveillance fee as required by section 14a of the act. The fee shall be calculated by the following formula:

Annual fee = $\$25.00 + (N \cdot I_c) + (P \cdot R_r)$

N = Numerical summary of the scheduled field investigations to be made at each location during the calendar year in which the surveillance fee is assessed based on the number of sources and the difficulty and frequency of investigation of each source.

$N = \Sigma (n_i)^{0.8} \cdot d_i \cdot f_i$

n_i = Number of sources with the difficulty of investigation equal to d_i.

d_i = Numerical ratio of the difficulty of investigation of a specified source to the difficulty of investigation of a solid waste incinerator with a capacity of 100 to 500 pounds per hour.

f_i = Number of times per year the source is scheduled for investigation.

I_c = Cost of investigation of a source of a 100 to 500 pounds per hour solid waste incinerator.

P = Fee related to other surveillance activities
$(\$100.00 \cdot A) + (\$30.00 \cdot B) + (\$15.00 \cdot C) + (\$0.50 \cdot D) + (\$0.10 \cdot E)$

A = Annual emission of all pollutants in group A, table 141, (tons per year).

B = Annual emission of particulate matter (tons per year).

C = Annual emission of sulfur dioxide (tons per year).

D = Annual emission of all pollutants in group D, table 141, (tons per year).

E = Annual emission of all pollutants in group E, table 141, (tons per year).

R_r = Correction factors to be established each year by the department on a regional basis. There shall be a correction factor for each of the 3 surveillance fee regions as shown in figure 141 of rule 4. The exact value of

each R shall be established so that the total amount of fees assessed in the region shall not exceed the total amount of fees appropriated to state and local air pollution control agencies for conducting air pollution surveillance in that region. The value of R shall not be more than 2.0.

(2) The difficulty factor (d_i), the frequency of investigation factor (f_i), and the unit cost of investigation (I_c) shall be established by the department by January 1 of each year. The d_i and the f_i factors may vary by county as established by the department.

(3) The annual emission rates shall be calculated using information reported to the department pursuant to rule 2 for the previous calendar year. The calculations shall be based on emission factors contained in the United States environmental protection agency office of air programs publication "Compilation of Air Pollutant Emission Factors," publication number AP-42, dated August 1977. The emission factors set forth in this publication are herein adopted by reference. The publication is available for inspection at the department and may be purchased from the Superintendent of Documents, U.S. Government Printing Office, Washington, D.C. 20402 at a cost of $9.75 or from the Department of Natural Resources, P.O. Box 30028, Lansing, Michigan 48909, at a cost of $9.75. For purposes of determining air contaminant emissions, if data considered by the department to be more reliable than the emission factors set forth in the publication are available, the more reliable data shall be used.

R 336.204. Annual surveillance fees; exceptions.

Rule 4. (1) A manufacturing or commercial location which is not scheduled for investigation by the department and in which the only source of an air contaminant listed in table 141 is a solid waste disposal incinerator with a combined design capacity of not more than 100 pounds of waste per hour or an internal combustion engine or boiler fired exclusively with gas or distillate oil, or both, with a combined heat input rate of not more than 10,000,000 Btu per hour, shall not be assessed a surveillance fee. However, all incinerators or boilers shall operate in compliance with all applicable air pollution control rules.

(2) Manufacturing and commercial locations which are not scheduled for investigation by the department and which annually emit less than 0.01 tons of group A pollutants, 1.0 tons of group B pollutants, 5.0 tons of group C pollutants, and 3.0 tons of group D and E pollutants shall be exempt from the fee.

(3) A manufacturing or commercial location which occupies under 3,000 square feet of floor space and which produces air contaminants only through the process of heating the premises of the business shall not be assessed a surveillance fee. However, all equipment used to heat the premises shall operate in compliance with all applicable air pollution control rules.

(4) Table 141 reads as follows:

TABLE 141

Register of materials

Group A

Asbestos
Benzo-a-pyrene
Beryllium or its compounds
Bromine
Chlorine
Cyanides
Fluorides
Fluorine
Iodine
Lead or its compounds
Mercaptans
Mercury or its compounds
Pesticides
Sulfides, organic or inorganic

Group B

Particulate (except those listed in group A)

Group C

Sulfur dioxide

Group D

Alcohols
Ethers
Esthers
Ketones
Halogenated hydrocarbons
Non-methane hydrocarbons

Group E

Oxides of nitrogen
Carbon monoxide
Ammonia

(5) Figure 141 reads as follows:

FIGURE 141

Air surveillance fee regions

R 336.205. Rescission.

Rule 5. R 336.81 to R 336.83 of the Michigan Administrative Code, appearing on pages 7926 to 7928 of the 1975 Annual Supplement to the Code and pages 8579 and 8580 of the 1976 Annual Supplement to the Code, are rescinded.

DEPARTMENT OF NATURAL RESOURCES

AIR POLLUTION CONTROL DIVISION

DISBURSEMENT OF AIR POLLUTION SURVEILLANCE FEES TO LOCAL UNITS

Effective Date: February 7, 1975

Filed with Secretary of State, January 23, 1975

These rules take effect 15 days after filing with the Secretary of State,

(By authority conferred on the department of natural resources by sections 5 and 14a of Act No. 348 of the Public Acts of 1965, as amended, being sections 336.15 and 336.24a of the Michigan Compiled Laws and Executive Orders No. 2 and 2a of 1973).

R 336.501. Purpose.

Rule 1. These rules set forth application requirements of local agencies for the receipt of air pollution surveillance fees collected by the department pursuant to section 14a of the act, contract requirements and surveillance fees disbursement procedures.

R 336.502. Definitions.

Rule 2.

(1) "Act" means Act No. 348 of the Public Acts of 1965, as amended, being sections 336.11 to 336.36 of the Michigan Compiled Laws.

(2) "Commission" means the air pollution control commission.

(3) "Contract" means an air pollution control agreement entered into by a local agency and the director to carry out that portion of a local program of air pollution control which is to be funded by surveillance fees collected by the department pursuant to the act.

(4) "Department" means the department of natural resources.

(5) "Director" means the director of the department.

(6) "Local agency" means a local unit of government or agencies thereof with an air pollution control program.

R 336.503. Local agency applications and program descriptions.

Rule 3. (1) A local agency requesting a portion of the surveillance fees collected by the department shall submit to the department, not later than 3 months prior to the beginning of the local agency's fiscal year, an application for surveillance fees to conduct a portion of its air pollution control program. The application shall include a program description as outlined in subrule (2) or (3).

(2) With its application, a local agency shall submit a detailed program description which shall include:

(a) A complete description of the local agency's entire air pollution control program including any applicable ordinances or rules associated therewith.

(b) A description of which activity or activities of the local agency's air pollution control program for which it requests surveillance fees.

(c) An itemized statement of all costs expected to be incurred or borne by the local agency for the conduct of its program including a delineation and justification of that portion of its air pollution control program to be funded by the surveillance fees.

(d) A description of how the local agency will coordinate its air pollution control program with the state air pollution control program and the compatibility of the local program with the state program.

(e) Any other item deemed necessary by the department or the applicant for inclusion in the program description by a particular local agency to carry out its functions which are funded in whole or in part by surveillance fees.

(3) The department may accept pertinent portions of a previously submitted federal grant application or a state surveillance fee application of any local agency instead of items required by subrule (2).

R 336.504. Submittal of application and program description to the commission.

Rule 4. (1) The department shall submit a copy of each local agency application and program description to the commission for its review and approval, and for the purpose of conducting public hearings pursuant to rule 134 of the general rules of the commission being R 336.134 of the Michigan Administrativ Code.

(2) Copies of a local agency's application and program description shall be available for inspection at the department's central and district offices

and at the offices of the local agency which submitted the application and program description.

R 336.505. Disbursement of surveillance fees to local agencies; contract requirements.

Rule 5. After receipt of a recommendation from the commission, but before disbursement of surveillance fees pursuant to the act or these rules, a local agency shall enter into a contract with the department which may include:

(a) A description of activities or functions which shall be undertaken by the local agency with the use of surveillance fees for air pollution control.

(b) A stipulation that the local agency shall enforce air pollution standards at least as restrictive as those of the commission for any activity undertaken by that local agency for air pollution control which is funded in whole or in part with surveillance fees.

(c) A stipulation that the local agency shall conduct investigations of air pollution complaints received by it or referred to it by the department or the commission which fall within the jurisdiction of the local agency.

(d) Provisions for keeping written records by the local agency to document the carrying out of the activities or functions undertaken by the local agency with the use of surveillance fees and the expenditure of funds.

(e) A requirement that a local agency shall provide 10 days notice of its intent to enter into litigation against an air pollution source which emits or may emit 100 tons per year or more of any air contaminant for which air quality standards have been promulgated by the United States environmental protection agency or by the commission, except for enforcement of a local agency rule or ordinance, to the director of the department. In specific situations, when a 10 day notice is not feasible, the local agency shall provide the maximum possible notice to the director but in any case notice shall be given the director prior to the local agency entering into litigation.

(f) A stipulation that the local agency shall cooperate with the department on sampling, monitoring, surveys, studies and preparation of related reports as may be agreed upon by the local agency and department.

(g) The method of reporting of data, expenditures or other information as may be required by the department.

(h) Recommendations by the local agency to the department on air pollution source site locations, permits, the location of sampling equipment or other matters that may be requested by the department.

(i) An agreement that the department shall return a specified portion of surveillance fees collected by it from air pollution sources pursuant to section 14a of the act to the local agency.

(j) Special conditions as set forth by rule 136 of the general rules of the commission being R 336.136 of the Michigan Administrative Code.

(k) Any other provisions required or deemed necessary by the department and agreed upon by the local agency, including the schedule of disbursement of surveillance fees by the director.

(2) A contract executed pursuant to this rule shall be signed by the director and the principal executive officer of the local agency or his duly authorized representative. The contract shall extend for not more than a single fiscal year of the local agency.

R 336.506. Local agency audit procedures.

Rule 6. A local agency which has received surveillance fees pursuant to the act and these rules shall submit to the department within 30 days of the beginning of each quarter of the local agency's fiscal year a complete itemized account of all funds expended during the previous quarter by that local agency

for that portion of the local agency's overall air pollution control program funded by surveillance fees, including a list of services performed and equipment purchased.

R 336.507. Surveillance fee disbursements and withholding.

Rule 7. (1) Disbursement of surveillance fees to a local agency may be on a quarterly basis, half year basis or in total, at the director's discretion, but in any case, the total disbursement of surveillance fees shall not exceed the total amount of surveillance fees appropriated by the legislature to be returned to local agencies.

(2) Upon a finding by the director that the local agency is violating any terms of the contract, he may withhold further disbursement of surveillance fees related to the contract terms violated.

(3) If the director determines that any modification, amendment or alteration to a local agency rule or ordinance is in conflict with the act, commission rules or the state implementation plan, he may withhold or withdraw payment of that portion of surveillance fees disbursed to the local agency to implement that rule or ordinance.

(4) The director shall seek the advice of the commission in carrying out his responsibilities pursuant to this rule.

R 336.508. Appeals.

Rule 8. If a local agency contests any action of the director taken pursuant to these rules, it shall have a hearing thereon, upon request therefor, in accordance with and subject to Act No. 306 of the Public Acts of 1969, as amended, being Sections 24.201 to 24.315 of the Michigan Compiled Laws.

APPENDIX B

MICHIGAN APPLICATION FOR
PERMIT TO CONSTRUCT
(Recommended Strategy)

AIR QUALITY DIVISION
MICHIGAN DEPARTMENT OF NATURAL RESOURCES
P.O. BOX 30028, LANSING, MICHIGAN 48909

APPLICATION NO

APPLICATION TO THE AIR POLLUTION CONTROL COMMISSION
for authority to construct, install or alter
and
for permit to operate process, fuel burning, refuse burning and/or air pollution control equipment

1 PERMIT TO BE ISSUED TO: (Business License Name of Corporation, Partnership, Individual Owner, Governmental Agency)
Department of Air Force

2 MAILING ADDRESS: (Number, Street, City or Village, Zip Code)
USAF Occupational & Environmental Health Lab, Brooks AFB, Texas 78235

3 EQUIPMENT OR PROCESS LOCATION: (Number, Street, City or Village, Township, Zip Code)
410th CSG/DEEV, KI Sawyer AFB, Michigan 49483

4 TYPE OF ORGANIZATION. ☐ Corporation ☐ Partnership ☐ Individual Owner ☒ Governmental Agency

5. GENERAL NATURE OF BUSINESS.
Air Force Base

6 EQUIPMENT DESCRIPTION: Application is hereby made for permission to construct, install or alter and to operate the following equipment
Two 60 MMBtu/hr (capacity each) boilers equipped with spreader stokers. The boilers will be capable of burning coal and/or wood.

7 ESTIMATED COST: Air Pollution Control Equipment $________ Total Project $________

8 PRESENT STATUS OF EQUIPMENT: (Check and complete applicable items)

	Estimated Starting Date	Estimated Completion Date
(X) Construction or installation not started		
( ) Construction or installation partly completed		
( ) Construction completed		
( ) Equipment is to be altered		
( ) Equipment is partly altered		
( ) Equipment has been altered		
( ) Change of location and/or ownership		

9 NAME OF PRIOR OWNER AS IN (1) ABOVE, AND PRIOR AIR POLLUTION CONTROL PERMIT NUMBER, IF ANY:
(Name) Same as 1 (Permit Number)

10 TYPE OR PRINT NAME AND TITLE OF OWNER OR AUTHORIZED MEMBER OF FIRM:
(Name)________ (Title)________
(Signature)________ (Date)________ (Phone No.)________

MDNR USE ONLY

11 DISPOSITION OF APPLICATION:

Permit to install approved and issued on ________ Signature ________

Permit to operate approved and issued on ________ Signature ________

FORM AP-1 1M 6/73 (Instructions for completing this form are on reverse side)

AIR POLLUTION CONTROL COMMISSION

AIR QUALITY DIVISION

MICHIGAN DEPARTMENT OF NATURAL RESOURCES

APPLICATION INSTRUCTIONS

Submit this form in triplicate; complete application requires specifications and drawings in duplicate. An application is required for basic processing equipment as well as air pollution control equipment. Basic equipment includes any article, machine, equipment or other contrivance, the use of which may cause the issuance of air contaminants. Air pollution control equipment includes any article, machine, equipment or other contrivance, the use of which may eliminate or reduce or control the issuance of air contaminants. One application will suffice for an interrelated process. This application must be signed by the owner or authorized member of firm. Please attach the following:

1. Equipment Location Drawings - Submit drawings showing:
   a. Plan view of owner's property to boundary lines; include outline and height of all structures.
   b. Locate and identify proposed equipment on property line.
   c. Locate and identify all adjacent properties and all structures within 150 feet of proposed equipment showing outlines and heights.
   d. Indicate north direction on drawing.
2. Equipment Specification - State make, model, size and type, etc. of proposed equipment and all major accessory equipment.
3. Process or Use Specification - Attach a complete written description of each process covered by this permit application. Explain clearly and in detail each process stage by including the nature, quantity, concentration, particle size, pressure, temperature, etc. of materials which may be discharged to the atmosphere. Prove sufficient control method detail to show the extent and efficiency of air pollution control devices.
4. Operating Schedule - Specify proposed equipment operating time in hours per day and days per week.
5. Process Weight - Detail type and feed rate in pounds per hour or similar measure for each process material charged.
6. Fuels and Firing Devices - Indicate for gaseous fuels: type and cubic feet per hour, for fuel oil: grade and gallons per hour, sulfur content, and specify temperature to which oil is preheated; for solid fuels: type, ultimate analysis and pounds per hour, indicate for firing device: make, model, size, type, number of devices and capacity range of each device (from minimum to maximum).
7. Flow Diagram - For continuous processes, show the flow materials either on a separate flow diagram or on the drawings accompanying the application.
8. Drawings or Equipment - Supply an assembly drawing, dimensioned to scale, in plan, elevation and as many sections as are needed to show, clearly, equipment design and operation and the means for controlling air contaminants. Structural design calculations and details are not required. When installing standard commercial equipment, the manufacturer's scale describing the equipment may be submitted in lieu of the parts of Item 8 that it covers. The following must be shown:
   a. Size and shape of the equipment; exterior and interior dimensions and features and materials of construction.
   b. Locations, sizes and shape details of materials handling equipment and all features which may affect the production, collection, conveying or control of air contaminants.
   c. Horsepower rating of driving motors.
   d. Additional information may be required.
   e. Indicate where in the system provision is made for source testing.
9. A permit application should pertain to an individual unit of equipment or to an operation or to a series of related operations within a process which are scheduled for simultaneous installation or alteration.

After authority to construct, install or alter is granted for any equipment, deviations from the approved plans and application information required are not permissible without first securing written approval.

Further information or clarification concerning permits can be obtained from the Air Quality Division Phone: (517)322-1333, (Lansing) Michigan Department of Natural Resources, P.O. Box 30028 Lansing, Michigan 48909

– Yellow copy to be retained by applicant –

ADDITIONAL INFORMATION FOR PERMIT TO CONSTRUCT

PROCESS/EQUIPMENT

Two new boilers each of 60 million Btu/hour capacity. The boilers will be capable of firing with coal and/or wood.

FLOW DIAGRAM AND PLOT PLAN

Flow diagram and plot plan are given in attachments I through V which show the following:

a. North direction for proper orientation
b. Building dimensions
c. Location of stacks
d. Plant boundary lines
e. Fuel unloading facilities
f. Fuel storage areas
g. Collected air contaminant silos

UTM COORDINATES

UTM coordinates for the new heating plant are:

X = 470.4 km, Y = 4131.0 km

UNCONTROLLED EMISSION RATE

Uncontrolled emissions for each boiler at full load when fired with coal are given below:

TSP = 208.5 lb/hr
SO_2 = 99.9 lb/hr
CO = 5.2 lb/hr
VOC = 2.6 lb/hr
NO_x = 39.5 lb/hr

CONTROL EQUIPMENT

Each boiler will be equipped with a mechanical dust collector and a baghouse. See attachment VI for more details.

CONTROLLED EMISSION RATES

Controlled emissions for each boiler will be as follows:

TSP = 2.09 lb/hr
SO_2 = 99.9 lb/hr
CO = 5.2 lb/hr
VOC = 2.6 lb/hr
NO_x = 39.5 lb/hr

TSP emissions are based on 99% control from the uncontrolled level.

FLOW RATE AND EXIT GAS TEMPERATURE

Flow rate for each boiler at full load would be 26,509 cubic feet per minute at 350°F.

OPERATING SCHEDULE

The new boilers will be capable of operating 24-hours per day, 365 days per year.

STACK HEIGHT AND DIAMETER

Each boiler will have a stack of 4.25 feet in diameter at the exit and 80 feet above ground level.

SOLID WASTE COLLECTION AND DISPOSAL

Each boiler will generate a maximum of 320 lb/hour of ash which will be collected from boiler bottom and control equipment. The collected ash will be stored in silos before disposal to landfill areas.

STACK MONITOR

There would be no continuous stack emissions monitor.

ATTAINMENT/NON ATTAINMENT STATUS

The area has been designated attainment for TSP, SO_2, CO, VOC, NO_x and lead and nonattainment for ozone.

PSD AND BACT APPLICABILITY

Since the increase in emissions for SO_2 and NO_x will be greater than the de minimus value, PSD regulations apply and Best Available Control Technology is required for these two pollutants.

NONATTAINMENT AREA REQUIREMENT

The area is nonattainment for ozone, but the increase in VOC emissions will be less than 50 tpy, hence, requirements for nonattainment areas do not apply.

BOILER DATA (AT MAXIMUM CAPACITY)

Feedwater = 60,000 lb/hour
Boiler efficiency = 85%
Heat Input = 70.6 MMBtu/hour
Type of firing = spreader stoker

FUEL AND ASH DATA

Type of fuel = Bituminous coal, wood, wood pellets
Source of coal = Reese Coal Company
Sulfur Content = 1.0% maximum
Grindibility of coal = 1/4" by 1/4"
Proximate analysis: Ash = 6.1%
Fixed carbon = 49 to 53%
Sulfur = 1.0%
Heating value = 13,420 Btu/lb
Volatile matter = 32 to 38%
Moisture = 5%
Ash fusion temp. = 2500 to 2700°F
Particle size analysis for ash = not available
Fly ash resistivity = not known
Method of collecting fuel data = to be obtained from fuel supplier

ASH HANDLING DATA

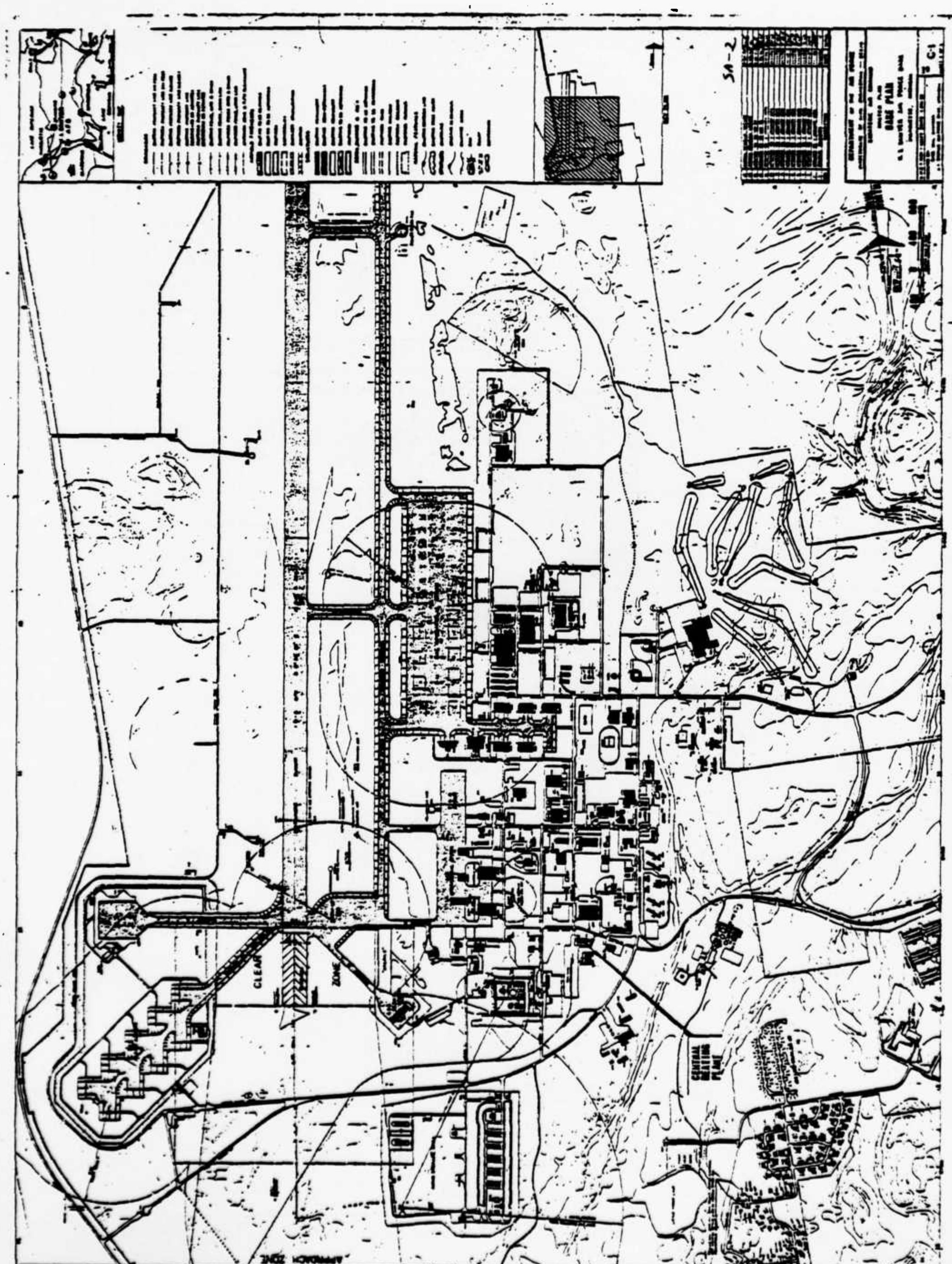
Description = see attachment VII
Method of control for displaced air at silos = not yet known
Method of transport from silo to landfill = trucks
Method of control while loading on truck, etc = enclosure
Amount removed by each truck etc = enclosure

FUEL HANDLING AND STORAGE DATA

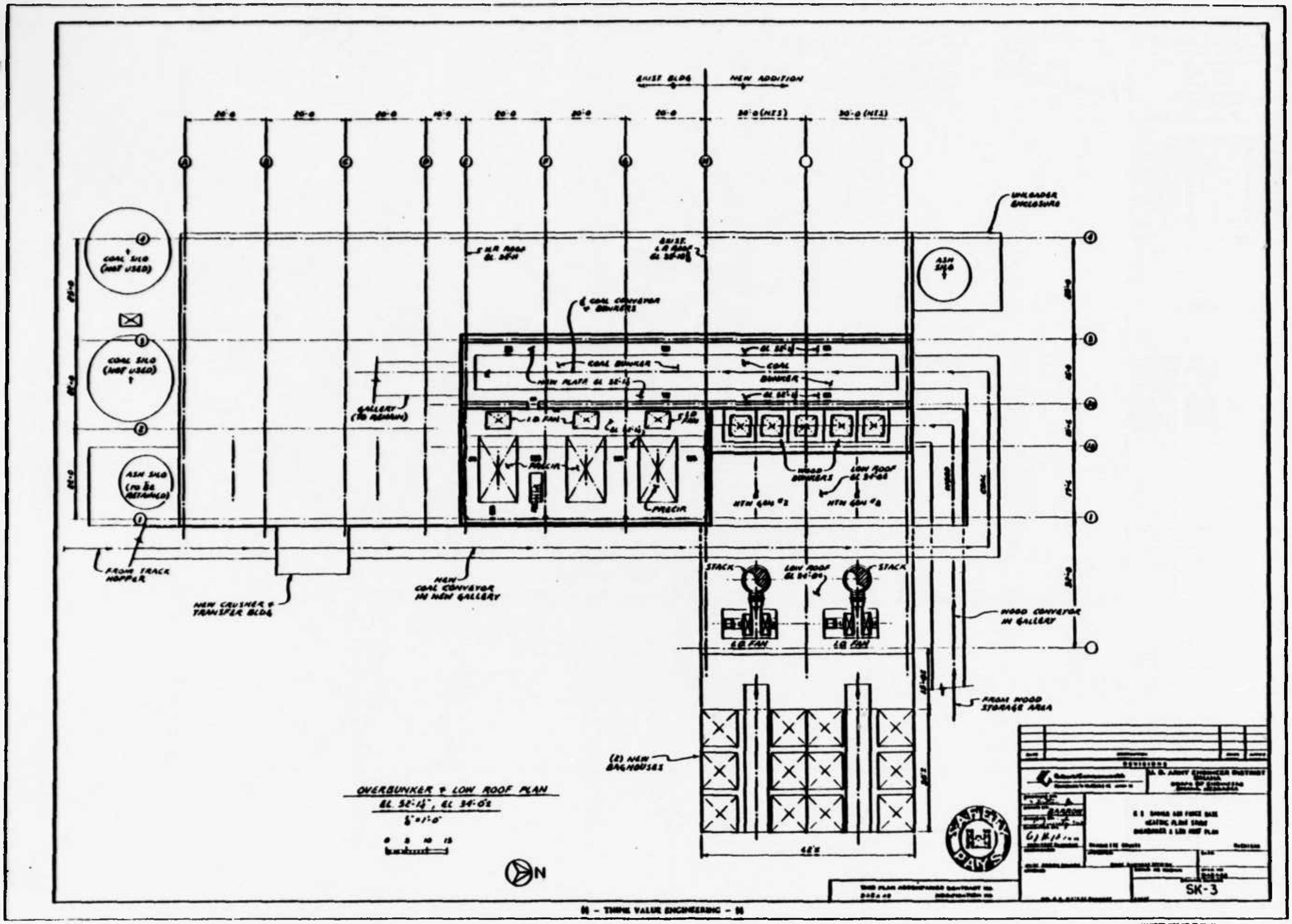
Method of transport to plant = rail road
Capacity of each railcar = 20 ton
Description = see attachment VIII
Control at transfer points = enclosure and wind guards
Conveyor descriptions and control = enclosure and wind guards
Stacking and reclaiming operations = not known
Amount of surfactant used to control coal pile = not known
Chemical analysis of surfactant = not known
For details see attachment VIII

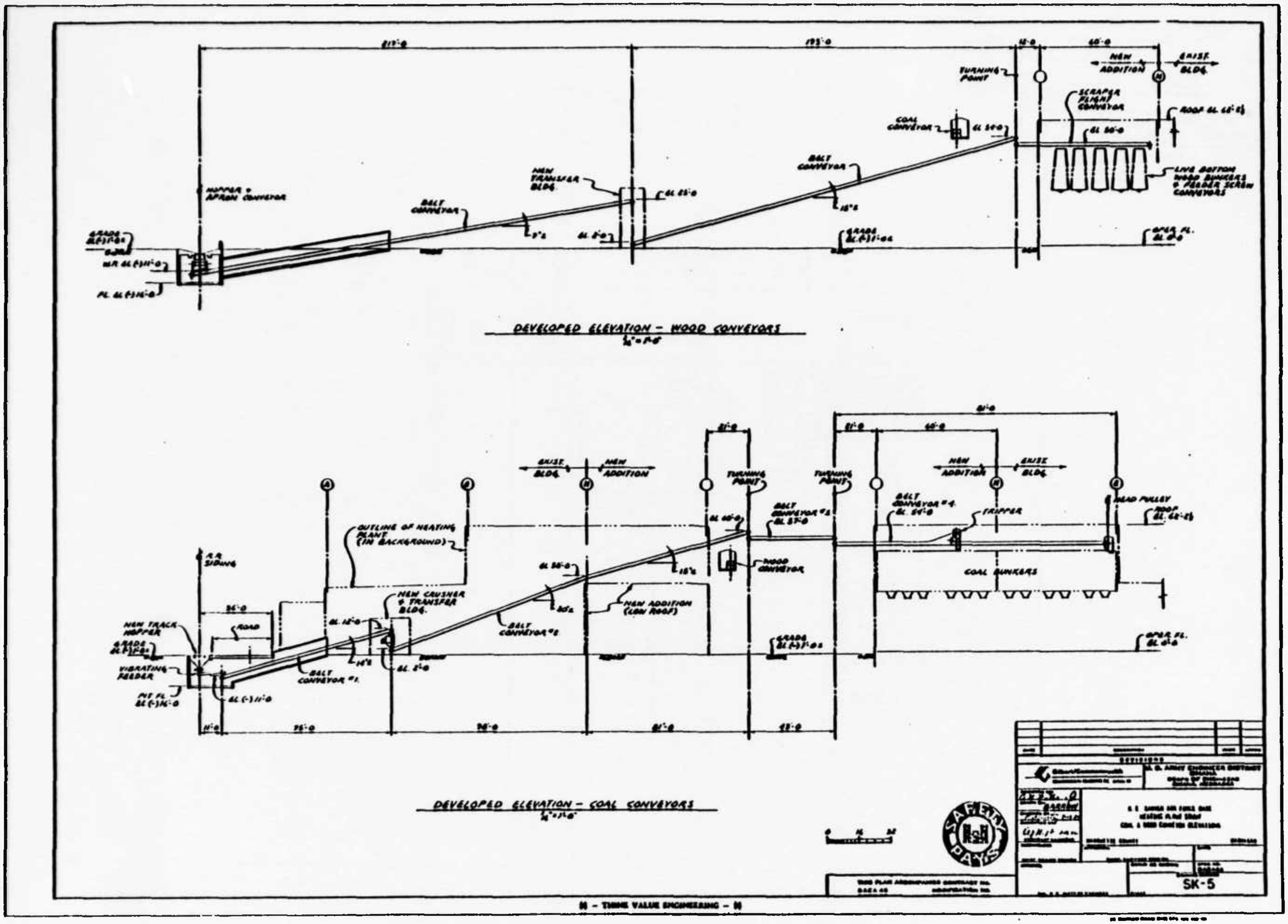
BAGHOUSE SPECIFICTAIONS

Number of isolated modules = 6
Fabric area = 28,140 sq. ft.
Air to cloth ratio = 1.51:1
Filter material = not known
Cleaning Mechanism = reversed air
Any cooling section = none
Fractional efficiency curve = not known
Pressure drop = 6" W.G. (maximum)

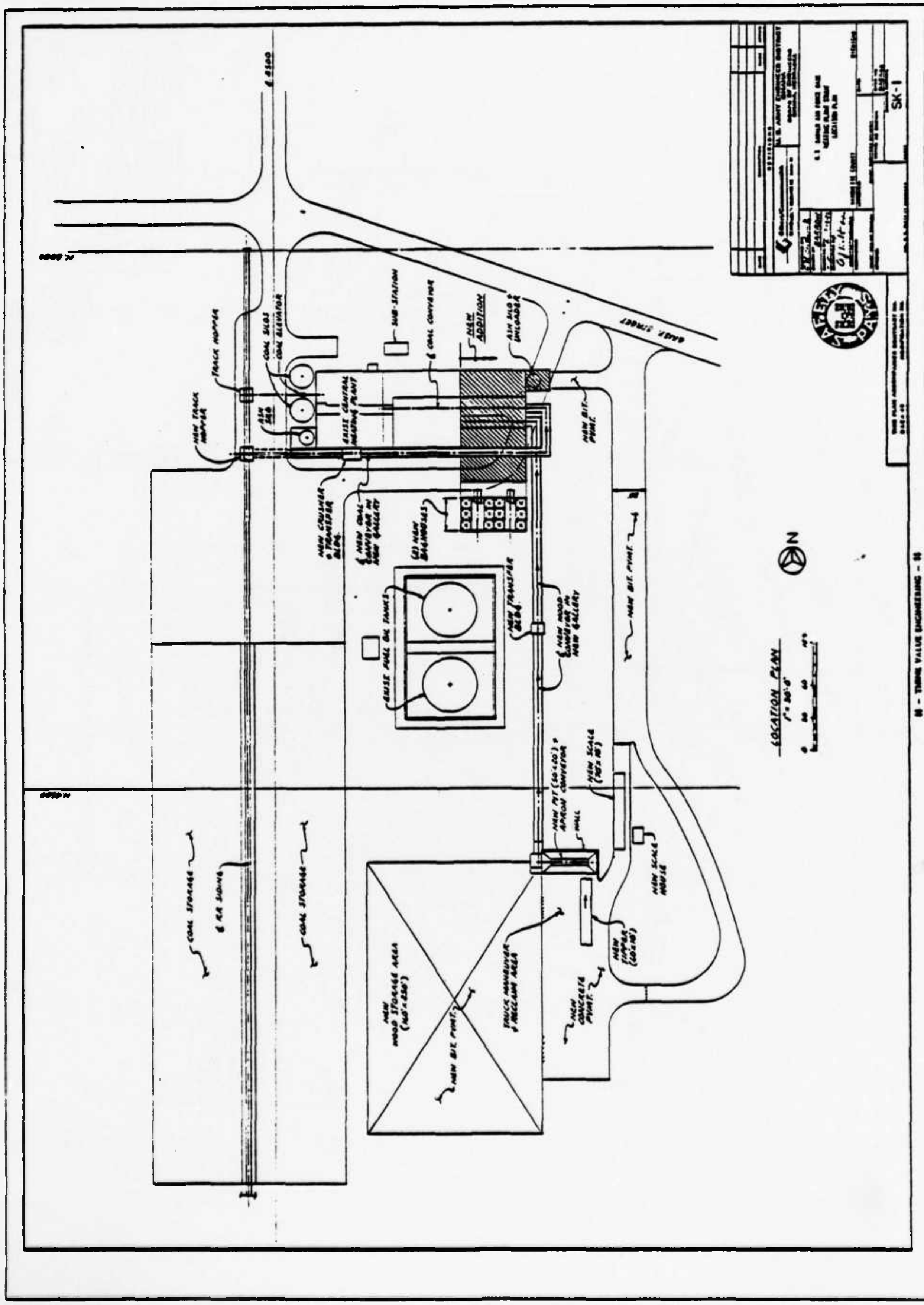


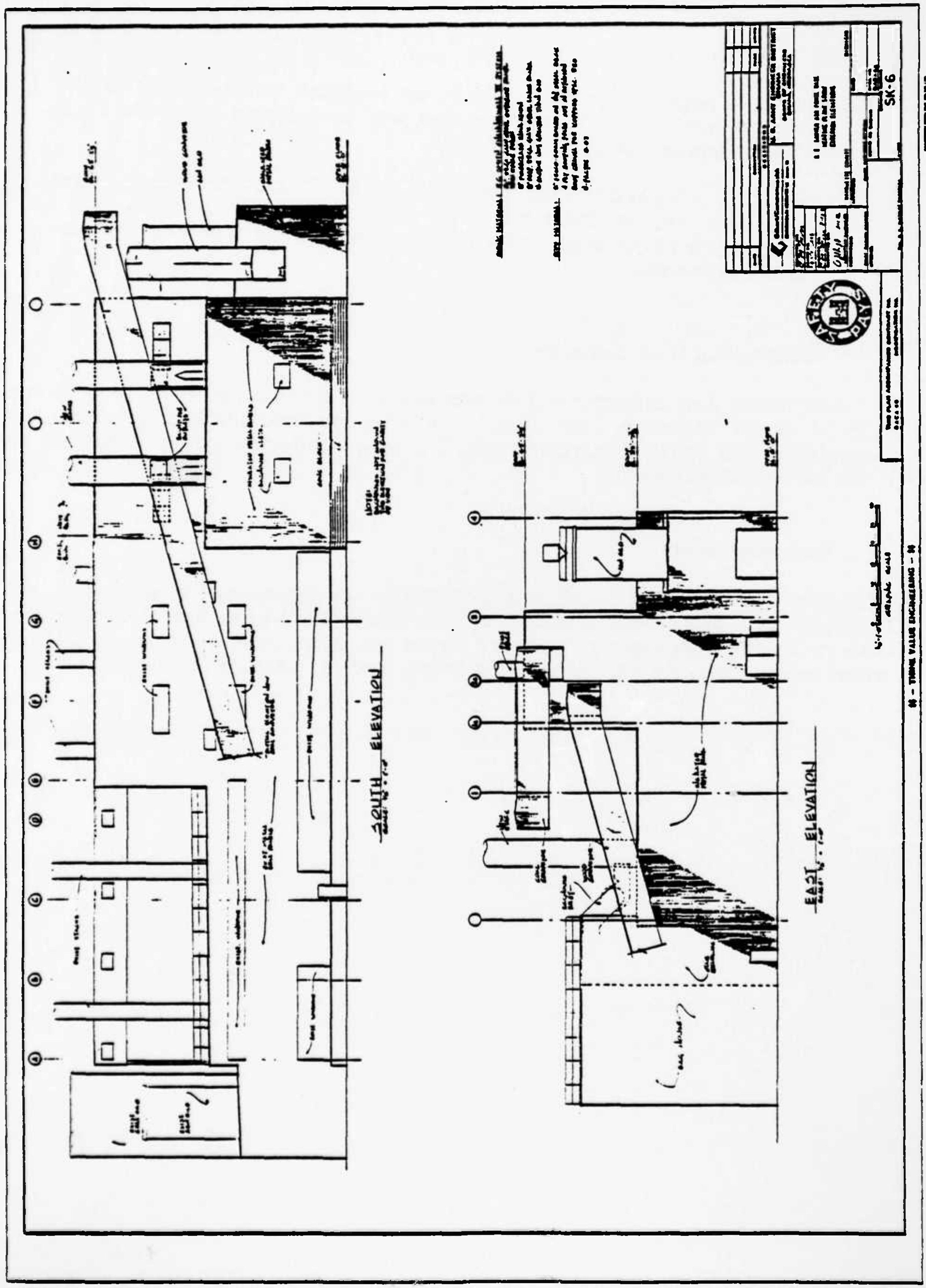
SA-2
BASE PLAN
C-1
CLEAR ZONE
APPROACH ZONE
CENTRAL HEATING PLANT


EXIST BLDG
NEW ADDITION
COAL SILO (NOT USED)
COAL SILO (NOT USED)
ASH SILO (TO BE RETAINED)
ASH SILO
UNLOADER ENCLOSURE
COAL BUNKER
NEW PLATF EL 52'-1½
PRECIP
LOW ROOF
STACK
STACK
WOOD BUNKERS
I.D. FAN
I.D. FAN
FROM TRACK HOPPER
NEW CRUSHER & TRANSFER BLDG
NEW COAL CONVEYOR IN NEW GALLERY
WOOD CONVEYOR IN GALLERY
FROM WOOD STORAGE AREA
(2) NEW BAGHOUSES
OVERBUNKER & LOW ROOF PLAN
SK-3
THINK VALUE ENGINEERING



DEVELOPED ELEVATION - WOOD CONVEYORS
DEVELOPED ELEVATION - COAL CONVEYORS
TURNING POINT
NEW ADDITION
EXIST. BLDG.
SCRAPER FLIGHT CONVEYOR
COAL CONVEYOR
BELT CONVEYOR
NEW TRANSFER BLDG.
HOPPER & APRON CONVEYOR
LIVE BOTTOM WOOD BUNKERS & FEEDER SCREW CONVEYORS
OUTLINE OF HEATING PLANT (IN BACKGROUND)
NEW CRUSHER & TRANSFER BLDG.
NEW TRACK HOPPER
VIBRATING FEEDER
R.R. SIDING
ROAD
NEW ADDITION (LOW ROOF)
WOOD CONVEYOR
TRIPPER
HEAD PULLEY
COAL BUNKERS
SK-5
III - THINK VALUE ENGINEERING - III


LOCATION PLAN
COAL STORAGE
TRACK HOPPER
COAL SILOS
COAL ELEVATOR
SUB-STATION
NEW ADDITION
GAIER STREET
SK-1


SOUTH ELEVATION
EAST ELEVATION
SAFETY PAYS
SK-6

Air Pollution Control Equipment

1. Install a negative pressure reverse air baghouse to serve the two new HTW generators. Each baghouse unit will be designed to handle a gas flow of approximately 42,400 ACFM.

2. Install a mechanical dust collector ahead of each baghouse. These collectors will be the mechanical single pass type, consisting of a multiplicity of cyclones, and will act as cinder traps to protect the bags in the baghouses.

Mechanical Dust Collector

A mechanical dust collector will be provided with each of the new HTW generators ahead of the baghouse. The collector will be the mechanical single pass type, consisting of a multipicity of cyclones. The flyash collected will be discharged into the ash handling system.

Baghouse Filters

Each new HTW generator will be provided with a negative pressure, reverse air baghouse. Each baghouse will consist of six modules and will be provided complete with structural steel support, inlet and outlet gas distribution manifolds, inlet and outlet valves, bags, system controls and stairs, ladders, platforms and railings.

ASH HANDLING SYSTEM

A new ash storage silo with mechanical exhauster and dustless unloader will be installed at the northeast corner of the extended heating plant. The silo will be constructed of steel and will be fourteen feet in diameter and 28 feet high with a net storage capacity of 3300 cubic feet or approximately 80 tons of coal ash which equals about six days output at full system load on coal. If equipped with nitrogen pressurization to prevent ignition from sparklers, the silo will have a capacity of 33 tons of wood ash or about 25 days operation at full load when firing on wood.

The dustless unloader and the motor-driven exhauster will be located in an enclosed room beneath the silo but still be at sufficient height above the road to permit gravity loading of ash into a truck. Metal siding matching the new heating plant enclosure will be extended around the silo, its top works, the dustless unloader room and the ash truck loading bay. This will minimize possible dust emission, sound transmission and the threat of freezing. Access to the equipment at the top of the silo will be from the gallery above the coal bunker.

Approximately 150 lineal feet of 8" alloy piping will be required to collect the ash from the four ash pit gates of the two new HTW generators. The 8" piping now serving HTW Generators 5 and 6 will be reassembled to connect these ash pit gates to the western end of the new 8" pipe.

Sixteen new power chamber operated fly ash intake assemblies will be furnished for rear-pass, air heater, and dust collector ash removal. Approximately 400 lineal feet of 6" alloy piping will be used to connect these gates in six separate lines leading to the 8" system. One 8" and six 6" air operated gate valves will permit evacuating one line at a time toward the silo. Rear pass and dust collector ash gates of the present two HTW generator will be connected to the far ends of the most convenient new 6" alloy pipe.

By adding 300 lineal feet of 8" alloy piping, two 8" power chamber operated valves, and increasing motor rating at the present ash system, the present ash silo, its exhauster, and dustless unloader can be retained as emergency or extra ash storage capacity. The present silo, however cannot be equipped with nitrogen pressurization for wood ash storage.

A control panel will be provided in the control room for controlling the timing and sequence of operation of the ash handling system.

Coal Handling System

Properly sized and oil treated coal is now brought to the plant by truck and dumped into the 8' x 8' track hopper if space is available or at a convenient point in the coal storage area located south of the track hopper. Coal is removed from the hopper by flight feeder to a by-pass around the present crusher to the boot of a bucket elevator.

The 35 ton per hour elevator delivers coal to either of two vertical cylindrical reinforced concrete silos or to a flight conveyor which supplies the 370 ton capacity bunker over the firing aisle of Generators 4, 5 and 6. A traveling weigh larry is used for conveying coal from the bunker or either silo to the respective stoker hoppers.

As part of the project for adding generating capacity to the central station, it is proposed that the present coal handling system be removed except the bunker located in front of Generators 4, 5, and 6 which will be extended past the new generators. An entirely new coal handling system rated at 50 tons per hour and avoiding the use of bucket elevators will be used to fill the enlarged bunker and distribute coal to the respective stokers.

A new 10' x 10' track hopper with 24" wide by 8' long vibratory feeder will be installed under the existing track at a distance of 55' south of the old hopper so that the conveyor belt leaving the pit toward the east can pass along the southside of the heating plant building.

Conveyor No. 1, as shown on Drawing No. SK-5, will receive coal from the vibratory feeder and carry it upward at a 14° slope to a point about 12' above grade and thus high enough to discharge into a new crusher with bypass, which in turn will feed a second inclined belt conveyor. Conveyor No. 1 will be 80' in length, 24" wide. Half will be underground and the second half enclosed in an 8' 6" diameter tubular gallery.

Conveyor No. 2 will be 24" wide by 194' long, totally enclosed in tubular gallery. This conveyor will deliver coal to No. 3 Conveyor, which is also 24" wide and runs north about 50 feet to deliver the coal to the eastern end of the over-bunker conveyor which is 24" wide and 140' long. A motor propelled tripper dumps coal from this conveyor to the full length of the coal bunker.

The coal conveying control system could be described as "manually started and automatically operated and stopped." When the coal attendant knows that he has coal at the track hopper and that it is required in the bunker, he will move the tripper to the east end of the bunker and start the conveyor system. If the coal in the hopper is oversized or frozen into lumps, he will also start the crusher. The tripper will move 5' westward each time its level sensing devices detect a full bunker beneath its current position until it reaches the western end of the bunker. It will then shut down the sytem and require manual restarting.

The enlarged coal bunker will have a storage capacity of 750 tons, all of which will be made available to any generators on line at any particular time by the use of an under-bunker conveyor and system of gates for removing coal from any section of the bunker and delivering it to any stoker.

Beneath the bunker and located at each stoker front will be an automatic coal scale for recording coal flow to the respective unit and a conical distributor for delivery of non-segregated coal sizes to each stoker feeder.

WOOD (OR PEAT) HANDLING SYSTEM

Wood chips or peat will be brought to the plant by semi-trailer trucks loaded in the forest from storage piles or directly from the wood or peat harvesting equipment. These trucks will enter the Central Heating Plant site from the north and ascend a slight grade travelling to the scales located about 300 feet south of the heating plant building. The scales and a tipper will be located at an elevation about ten feet above the level of the wood and peat storage area. The scales will print a weight ticket for the driver and record the weight on a printed log sheet.

Upon leaving the scales the truck will be turned 90^{o} to the left and backed onto a hydraulically operated tipping platform which will tilt the front of the truck upward until the bed of the trailer is inclined at an angle of 60^{o}. The tailgate of the truck will overhang the retaining wall at the rear of the tipper and will be about ten feet above the level of storage yard below. A rubber-tired bulldozer at the storage yard level will push the chips into storage to make room in the tipping area for the next truck.

Chips will be bulldozed from storage piles to a feeder pit located near but not adjacent to the tipping area. Effort will be made to allow equal storage time for all chips by each day removing first those chips which have been in the yard for the longest time. The feeder will consist of a pit of about 3 feet deep by 5 feet wide by 10 feet long with a 3 foot wide apron feeder conveyor in the bottom. This feeder will discharge onto a 36" wide inclined belt conveyor which discharges onto a horizontal flight scraper conveyor passing over the tops of the wood storage bins in the plant.

In the heating plant there will be five wood storage bins, each capable of holding sufficient wood chips to run one of the 55×10^6 Btu/hr HTW generators for one hour. Each bin will be five feet square at the top and eight feet square at the bottom to avoid the possibility of chips wedging or arching while moving downward. Walls of the bins will be constructed of 304 stainless or stainless-clad steel. Five 8" screw conveyors placed side by side across the bottom of each bin will propel the chips to a vertical chute leading downward to the windswept feeders at the stoker front. The first two bins will serve Generator No. 8 exclusively, the third bin will be a shut-down surge bin, and the last two bins will serve Generator No. 7 exclusively.

A special loading sequence of the five wood storage bins will optimize the availability of bin storage and also protect the conveyors from having to start when loaded with chips. Level sensing devices in the four bins serving the two new generators will govern the operation of gates in the floor of the distributing scraper conveyor as well as the stopping of the feeder putting chips onto the first conveyor.

The first two discharge gates of the distribution conveyor serve Generator No. 8. They will be adjusted to remain open as long as the respective bins are less than full. The third gate feeds the surge bin and will remain closed as long as any of the other gates are open. The fourth gate supplies the first bin serving Generator No. 7 and will operate the same as the gates serving Generator No. 8. The fifth bin will not be equipped with an entry gate, but a medium-high level sensing device in this bin will stop the chip feeder at the storage yard and a high level sensing device will

open the surge bin entry gate (Gate No. 3). Stopping the initial feeder before opening the surge bin gate may in some cases reduce the frequency of conveyor starts and stops and will also provide a place for a larger quantity of chips already on the belts. Conveyors will stop when motor current reduction indicates that the belts are running empty.

The surge bin is identical to the other four except that it discharges into a small run-around elevator which carries its chips to the top strand of the scraper distribution conveyor, thus allowing these chips to re-enter the system. Upon re-start of the system, as a result of one or more bins indicating less than safe minimum contents, the flight conveyor and run-around elevator start first and the inclined conveyor and its feeder start shortly thereafter. Appropriate bin entry gates will open to receive the chips where needed.

Since it is planned to use the two 30×10^6 Btu/Hr HTW generators in summer or in conjunction with a 55×10^6 Btu/hr unit at other times, provision must be made for feeding wood chips to these units. A pneumatic conveyor system loading from the discharge spout of the fifth wood storage bin will be provided for this service.

<u>Capacities of Wood (or Peat) Handling System</u>

Hourly Wood Burning Rates:

Per 55×10^6 Btu/Hr Generator	=	8 tons/hr
Per 30×10^6 Btu/Hr Generator	=	4-1/2 tons/hr
At 110×10^6 Btu/Hr Peak	=	15-1/2 tons/hr

Holding Capacity Per Bin:

Hours Operating From 4 Full Bins @ Full Load	2 Hrs
Conveyor and Distributor Capacity	40 Tons/Hr

APPENDIX C

DESCRIPTION OF DISPERSION MODELS

APPENDIX C

DESCRIPTION OF DISPERSION MODELS

Three basic dispersion models were used in evaluating the air quality impacts of emissions from the proposed source and other sources in the area. These are:

- o Air Quality Display Model (AQDM)
- o Single-Source Model (CRSTER)

The Air Quality Display Model was used to determine the annual average impact. A modified version of the Single-Source Model was used for predicting the short-term concentrations, such as 3-hour and 24-hour averages. Industrial Source Complex Model was used to evaluate the air quality impacts under downwash conditions.

The air quality models can be categorized into four general classes: Gaussian, numerical, statistical and physical. Within some of these, a large number of individual "computational algorithms" exist, each with its own specific applications. All the three models used in this analysis are Gaussian models which are generally considered to be state-of-the-art techniques for estimating the impact of nonreactive pollutants.

AIR QUALITY DISPLAY MODEL (AQDM)

The model which was used to predict the annual average impact on ambient air quality is the AQDM. This model was developed for the U.S. Department of Health, Education and Welfare, National Air Pollution Control Administration which is the predecessor organization of the U.S. Environmental Protection Agency. The model was completed in 1969 and was intended to help state and local air pollution control agencies to evaluate the effect of emission regulations on ambient air quality. The AQDM was originally developed by Martin-Tikvart in 1968 and they have made several simplifying assumptions that differ from the work completed by Turner, Pasquill-Gifford and others. These modifications will be discussed later.

The specific computer program was obtained from the U.S. EPA in North Carolina in the fall of 1973 with program changes supplied by EPA for incorporating the Briggs plume rise equation. The 1969 version of AQDM

utilized the Holland equation when calculating plume height. All AQDM runs were made on an IBM 3033 computer.

The model inputs included meteorological and point source emission data. The emission stack configuration parameters were also required to estimate annual average ground level concentrations. Other inputs regarding study area location and grid spacing were also included.

Assumptions of the Air Quality Display Model

There is very little difference in any of the presently published air quality dispersion models. All of the models assume some form of conical dispersion pattern and make assumptions about the terrain and secondary atmospheric reactions which help reduce the number of input parameters. Frequently, investigators tailor a model to their local conditions by measuring air quality and then apply correction factors to different portions of the dispersion equation.

It is important to point out key assumptions that have been made in simplifying the basic equations for use in this dispersion model. The assumptions incorporated in the Gaussian plume equation and the AQDM can be summarized as follows:

1. The plume description represents conditions averaged over a time period of several minutes. At any given time, the behavior of the plume is more complex, particularly during unstable conditions.

2. The pollutant has neutral buoyancy in the atmosphere; that is, no fall-out is modeled by the equation. Most particulates with equivalent diameters less than 20 microns satisfy this assumption.

3. The time-averaged plume exhibits a Gaussian distribution of concentrations in the cross-plume and vertical dimensions. The measures of the spread in both directions (the standard deviations) are considered to be a function of downwind distance and atmospheric stability only.

4. The plume is assumed to be steady state, resulting from a continuous and constant source.

Plume Behavior

The AQDM was developed to estimate ambient air concentrations over a very large built up metropolitan area. The developers of the AQDM used Chicago as their test city and obvious inputs to the model included a number of area, point, and transportation sources. For calibration of the model, the developers had available an abundance of air quality data representing various averaging times collected over several years.

One of the key differences that has been made in the current AQDM from that of the earlier investigators in the treatment of the crosswind deviations (σ_y). Most investigators assume the Gaussian distribution.

The AQDM, on the other hand, uses a linear distribution. In general, the linear distribution in the AQDM is more applicable to large built up metropolitan areas where channeling, turbulence, and multiple sources create a more uniform distribution of the ground level concentrations. In rural situations involving several point sources other investigators have used the Gaussian distribution for the σ_y's and σ_z's.[a] The effect on ground level concentrations of using a linear distribution would probably be to estimate lower maximum ground level values. Furthermore, the expected location of the maximum may differ from those formulae assuming a Gaussian distribution for σ_y.

An estimate of the concentration for a specific source-receptor relationship is obtained by choosing a representative speed for each wind class and solving the equation for all wind speed and stability classes. The average concentration is obtained by summing all concentrations and weighting each one according to its frequency for the particular wind speed, wind direction, and stability class. To obtain the total concentration at a specific receptor, the results of the equation are summed over all sources.

Plume Rise

All plume rise formulae consider the rise due to two effects: momentum and buoyancy. The momentum term depends upon physical stack parameters, exit velocity and diameter; the buoyancy term depends upon heat parameters, heat emission rate or the difference between effluent and ambient air temperature.

There are over 100 such formulae and probably 50 papers published reviewing and analyzing their accuracy and applicability. Without exception, the investigators have concluded that none predicts plume rise accurately under all meteorological conditions.

The AQDM originally utilized the Holland plume rise equation. In 1969, the Holland equation was in fact the preferred equation of the meteoological fraternity. Since then, however, Briggs published his (latest) equation in 1971 and provided supporting data to establish the validity of the estimates provided by his equation. The Holland formula is now known to greatly underpredict plume rise while the Briggs formula is believed to be more accurate under most conditions. At the present time, EPA meteorologists are advising use of the Briggs equation.

ES-MODIFIED SINGLE SOURCE (CRSTER) MODEL

The model which was used to predict short-term impacts of SO_2 emissions on ambient SO_2 levels is a modified version of the CRSTER Model. The original single source model was developed by the Meteorology Laboratory of the U.S. EPA in 1972. Since that time, numerous modifications

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[a] Jensen, A.F. and Weil, J.C., Maryland Power Plant Air Monitoring Program Preliminary Results, presented at APCA Meeting in Chicago, June 1973, (Paper No. 73-147).

and revisions have been added to the computer program to increase its utility. Recently, ES expanded the capabilities of CRSTER.

The types of application for which the model was designed include:

- o Stack design studies
- o Combustion source permit applications
- o Regulatory variance evaluation
- o Monitoring network design
- o Control strategy evaluation for SIPs
- o Fuel conversion studies
- o Control technology evaluation
- o Design of supplementary control systems
- o New source review
- o Prevention of significant deterioration (PSD)

The model has been successfully applied previously to these types of problems.

Modified CRSTER is a steady-state Gaussian plume technique applicable to both rural and urban areas in uneven terrain. The purpose of the technique is to: determine maximum short-term concentrations over a one year period due to point source emissions, determine the meteorological conditions which cause the maximum concentrations, and store concentration information useful in calculating frequency distributions for various averaging times. The concentration for each hour of the year is calculated and midnight-to-midnight averages are determined for each 24-hour period. The model also calculates eight, 3-hour concentrations for each day of meteorological data.

The model inputs include meteorological data, point source emission data, and receptor elevations. Emission stack configuration parameters are also required to estimate short-term ground-level concentrations of air pollutants. Other inputs regarding study area location and grid spacing are also included.

Assumptions of the Modified CRSTER Model

The modified CRSTER is based on a recent version of the Gaussian plume equation. The model assumes a continuous emission source, steady-state downwind plume, and a Gaussian distribution for concentrations of pollutants within the plume in both the crosswind and vertical directions. Plume rise is estimated using equations proposed by Briggs for hot, buoyant plumes. As the plume expands due to eddy diffusion, it is diluted and transported downwind by the mean wind. The rate of expansion is characterized by a series of empirical dispersion coefficients which are dependent on the stability of the atmosphere, as determined in studies made by Pasquill and Gifford, and reported by Turner.

The assumptions incorporated in the Gaussian plume equation and the modified CRSTER Model can be summarized as follows:

- o The pollutant emitted is a stable gas or aerosol which remains suspended in the air and participates in the turbulent movement

of the atmosphere; none of the material is removed as the plume advects and diffuses downwind and there is complete reflection at the ground.

- The pollutant material within the plume takes on a Gaussian distribution in both the horizontal crosswind and vertical directions, described by empirical dispersion parameters σ_y and σ_z.

- The plume is assumed to be steady-state, resulting from a continuous and constant source.

Plume Behavior

As previously mentioned, the modified CRSTER Model assumes a continuous emissions source, steady-state downwind plume, and a Gaussian distribution for concentrations of the pollutant within the plume in both the crosswind and vertical directions. The general Gaussian plume equation used in the modified CRSTER Model for a continuous emission source gives the local concentration of a gas or aerosol at a ground-level location (x,y) by the following expression:

$$X(x,y) = \frac{Q}{\Pi \sigma_y \sigma_z u} \exp -\frac{1}{2}\left(\frac{y}{\sigma_y}\right)^2 \exp -\frac{1}{2}\left(\frac{H}{\sigma_z}\right)^2$$

where the wind is advecting the plume at a speed u along the x-axis and dispersing it along the crosswind and vertical direction with diffusion coefficients σ_y, and σ_z, respectively. The pollutant emission from the source is at a uniform rate Q and is assumed to be released at an "effective stack height" H. It is assumed that complete reflection of the plume takes place at the earth's surface, i.e., there is no atmospheric transformation or deposition at the surface. The concentration is an average over the time interval represented by σ_y and σ_z. The modified CRSTER Model calculates short-term concentrations and uses these directly as 1-hour average concentrations without consideration of plume history, i.e., each 1-hour period is completely independent.

The empirical dispersion coefficients, σ_y and σ_z, used in the modified CRSTER Model are those suggested by Pasquill and Gifford and reported by Turner. Values for σ_y and σ_z are represented as a function of downwind distance from the emissions source and the stability of the atmosphere. These values are representative for a sampling time of up to about 1-hour and were developed based on aerometric measurements taken in open, level to gently rolling country.

Atmospheric stability is determined indirectly from the amount of incoming solar radiation at the surface (insolation), and the wind speed. Pasquill suggested a six category classification scheme from A for extremely unstable to F for moderately stable, based on the range of these two parameters. Because solar radiation is not widely measured parameter, Turner developed an objective classification method based on cloud cover, ceiling height, and solar elevation. The modified CRSTER Model calculates the stability classification by this method for each hour from the recorded meteorological observations.

The wind speed required for input to the modified CRSTER Model is considered to be representative of the conditions throughout the vertical height interval in which the plume is dispersing. The wind at the stack elevation is commonly used as an approximation to this condition. Because the wind is generally measured near 7 meters by the National Weather Service (NWS), an adjustment is made in the model by the following power law relationship:

$$u = u_o \, (h/7)^p$$

where: u = hourly wind speed at stack height (m s^{-1})
u_o = hourly wind speed near 7m above the ground (m s^{-1})
h = stack height (m)
p = wind profile exponent

The profile exponent p is a function of stability and has the values given in Table B.1. The adjusted wind speed is used by the model to calculate plume rise and dilution.

Turbulent mixing and vertical diffusion of a plume is often limited by the existence of a stable layer of air aloft, i.e., an inversion layer. The effects of limited mixing (or plume "trapping") on plume dispersion are incorporated into the modified CRSTER Model by the assumption that the plume is completely reflected at the mixing height, as well as the ground. Since multiple reflections are possible, trapping is simulated using the method of multiple images proposed by Bierly and Hewson.[a] In this procedure, each reflection is represented by an "image plume" from an imaginary source with a "stack height" equal to the vertical distance traveled by the plume "edge" to the point of ground reflection. The reflections between the mixing height (L) and the ground are represented by the convergent infinite series of Gaussian plume terms given in Table B.2. Another assumption is that whenever the plume centerline is above the mixing height at a given receptor location, there is no contribution from the plume at that receptor.

Plume Rise

The effective height of emission used in the Gaussian plume equation is defined as the sum of the physical stack height and the plume rise. Estimates of plume rise are required to predict the dispersion of continuous gaseous emissions possessing buoyancy. The rise of emission plumes above their source release height often accounts for a significant reduction in related ground-level concentrations.

Plume rise in the modified CRSTER Model is estimated using equations proposed and later modified by Briggs. These equations are based on the assumption that plume rise depends on the inverse of the mean wind speed and is directly proportional to the 2/3 power of the downwind distance

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[a] Bierly, E.W. and Hewson, E.W., "Some Restrictive Meteorological Conditions to be Considered in the Design of Stacks", Journal of Applied Meteorology, 1:383-390, March 1962.

from the source, with different equations specified for the neutral, unstable and stable conditions. Only the final plume rise as predicted by Briggs is used in the modified CRSTER Model. Briggs' plume rise equations are detailed below, where all symbols are defined in Table A.3.

- For unstable or neutral atmospheric conditions, the downwind distance of final plume rise is $x_f = 3.5\ x^*$, where:

$$x^* = 14\ F^{5/8},\ \text{when } F < 55\ m^4\ s^{-3}$$

$$x^* = 34\ F^{2/5},\ \text{when } F \geq 55\ m^4\ s^{-3}$$

The final plume rise under these conditions is:

$$h = 1.6\ F^{1/3}\ (3.5\ x^*)^{2/3}\ u^{-1}$$

- For stable atmospheric conditions, the downwind distance of final plume rise is $x_f = u\ s^{-1/2}$, where:

$$s = g\ \partial\theta/\partial z\ T^{-1}$$

The plume rise is:

$$h = \begin{cases} 2.4\ [F/(u\ s)]^{1/3}, & \text{for windy conditions} \\ 5\ F^{1/4}\ s^{-3/8}, & \text{for near calm conditions} \end{cases}$$

The final plume rise given by these formulae does not take cognizance of "negative" buoyancy due to cold plumes, or aerodynamic effects from flow fields around the stack or nearby tall buildings and prominent terrain. The final plume height used by the modified CRSTER Model does not follow changes in terrain height, as described later in this appendix in the discussion of terrain considerations.

Urban-Rural Considerations

The principal difference between dispersion coefficients in rural and urban environments is associated with the occurrence of the nocturnal, ground-based temperature inversion. On calm, clear nights, radiational cooling can produce such an inversion, and hence stable atmospheric conditions, in a rural environment. Such inversions do not occur, though, in urban areas, due primarily to the influence of a city's larger surface roughness and the release of stored heat from structural surfaces, i.e., the urban heat island effect. Thus, stable atmospheric conditions do not occur near the ground in urban areas on calm, clear nights.

The modified CRSTER Model accounts for these effects in both the choice of dispersion coefficients and mixing heights. If an urban application is indicated, stability categories E and F default to category D for the purpose of determining σ_y and σ_z. Separate sets of hourly mixing height data, for urban and rural environments, are input to the model and it chooses between these, depending on the conditions indicated.

Terrain Considerations

The modified CRSTER is an uneven terrain model that takes into account certain changes in ground elevation between the point of source emissions (the plant) and the surrounding grid receptor points. The basic method used in the model for making terrain adjustments is illustrated in Figure B.1. For receptors with elevations greater than the stack elevation but less than the top of the lowest stack, the difference in elevation is subtracted from the effective plume height. The terrain adjustment made for any one receptor point does not affect concentrations at any other receptor point. When the height of a receptor is above the shortest stack height, plume impaction on surrounding terrain is possible and the model terminates. Therefore, some receptor elevations were modified so that none were above the shortest stack height. The model considers receptors below the ground elevation of the plant to be at plant elevation.

Figure B.1 also illustrates the mixing height assumption. This permits calculations to be made using the modified Gaussian equations without adding a vertical displacement term. This method of treating terrain adjustments assumes ground-based receptors and is not equivalent to simply including a vertical coordinate term z in the Gaussian plume equation. The method would not imply any changes in terrain elevation at all. Rather, the value of z would specify the height at which the receptor point would be "floating" in the air, and reflections of the plume at the ground close to the stack, caused by elevated terrain, would not be simulated.

TABLE C.1

WIND SPEED PROFILE EXPONENT

Pasquill Stability Class	Wind Speed Profile Exponent, P
A = extremely unstable	0.10
B = moderately unstable	0.15
C = slightly unstable	0.20
D = neutral	0.25
E = slightly stable	0.30
F = moderately stable	0.30

TABLE C.2

MODIFIED GAUSSIAN PLUME EQUATIONS USED
IN THE MODIFIED CRSTER MODEL

If $H \leq L$ and $z \leq 1.6L$	$X = \frac{Q}{\pi \sigma_y \sigma_z u} \exp \left[-\frac{1}{2} \left(\frac{y}{\sigma_y} \right)^2 \right] \sum_{N=-\infty \; (-k)}^{+\infty \; (+k)} \exp \left[-\frac{1}{2} \left(\frac{H+2NL}{\sigma_z} \right)^2 \right]$
If $H \leq L$ and $z > 1.6L$	$X = \frac{Q}{\sqrt{2} \, \sigma_z \, Lu} \exp \left[-\frac{1}{2} \left(\frac{y}{\sigma_y} \right)^2 \right]$
If $H > L$	$X = 0$

APPENDIX D

SAMPLE COMPUTER PRINTOUTS

PRINTOUT

CRSTER MODEL RUN FOR
EXISTING BOILERS (ACTUAL EMISSIONS)

The existing boilers were modeled as one emission point. The emission rate used in the model was the sum of emissions from the five existing boilers. The flow rate used in the model was the average of the five flow rates since each boiler has its own stack.

```
PLANT NAME: FT SAWYER AFB              POLLUTANT: SO2       AIR QUALITY UNITS: UG/M**3
*** EXISTING PLANT *** ALL DAYS *** 121 RECEPTORS *** 1 KM GRID SPACING ***

             MET FILE      REQUESTED
            STN NO. YR   STN NO. YR
 SURFACE     94836  64    94836  64
 UPPER AIR   14847  64    14847  64
PLANT LOCATION: RURAL
NO TAPE OUTPUT
O VALUES REQUIRE MONTHLY INPUT
F VALUES REQUIRE MONTHLY INPUT
MET DATA WILL NOT BE PRINTED

DAY-- 1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1
      1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1
      1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1
      1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1
      1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1
      1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1
      1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1 1 1 1 1
      1 1 1 1 1 1 1 1 1 1   1 1 1 1 1 1


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     ALL TABLES, INCLUDING SOURCE CONTRIBUTION, THAT CONTAIN "ANNUAL" IN THE HEADING ARE BASED ONLY ON THOSE DAYS

     MARKED BY "1" IN THE ABOVE TABLE
```

ST	IDENT	MONTH	U T M EAST	U T M NORTH	EMISSIONS (GM/SEC)	HEIGHT (METERS)	DIAMETER (METERS)	VELOCITY (M/SEC)	TEMP (DEG.K)	FLOW RATE (M**3/SEC)	ELEV (FEET)
1	STACK NO. 1	JAN	470.4	5131.0	17.8900	25.0	1.3	7.8	456.	10.3	0.0
		FEB			16.4000			7.1	456.	9.4	
		MAR			15.0300			6.5	456.	8.6	
		APR			10.9300			4.7	456.	6.3	
		MAY			7.5000			3.2	456.	4.3	
		JUN			5.4700			2.3	456.	3.1	
		JUL			3.9800			1.7	456.	2.3	
		AUG			5.0900			2.2	456.	2.9	
		SEP			5.8400			2.6	456.	3.4	
		OCT			9.9400			4.3	456.	5.7	
		NOV			11.9300			5.2	456.	6.9	
		DEC			14.1600			6.1	456.	8.1	

PROJECT: KI SAWYER AFB POLLUTANT: SO2 CONCENTRATION UNITS: UG/M**3

MAXIMUM CONCENTRATIONS AT EACH RECEPTOR

#	1-HOUR		3-HOUR		0-HOUR		24-HOUR		ANNUAL
MAX	152.5	(16.12)	113.5	(29, 3)	0.0	(0, 0)	46.7	(48)	3.2
RCP	72		73		121		73		73
1	73.3	(100,21)	20.0	(100, 7)	0.0	(0, 0)	4.0	(16)	0.2
2	89.7	(52,20)	40.9	(52, 7)	0.0	(0, 0)	5.8	(52)	0.2
3	87.6	(359, 6)	65.4	(359, 2)	0.0	(0, 0)	8.9	(286)	0.2
4	74.1	(67,20)	33.8	(31, 8)	0.0	(0, 0)	9.6	(31)	0.2
5	69.5	(310,23)	32.3	(318, 8)	0.0	(0, 0)	9.1	(24)	0.1
6	72.0	(319,21)	27.4	(19, 7)	0.0	(0, 0)	5.0	(150)	0.2
7	50.1	(82,23)	16.8	(319, 3)	0.0	(0, 0)	3.3	(319)	0.1
8	47.8	(319,18)	10.5	(329, 1)	0.0	(0, 0)	4.0	(329)	0.1
9	39.9	(194,22)	18.1	(12, 1)	0.0	(0, 0)	2.6	(194)	0.1
10	42.6	(314,12)	19.7	(314, 4)	0.0	(0, 0)	4.5	(319)	0.1
11	71.8	(110, 4)	44.7	(110, 2)	0.0	(0, 0)	5.6	(110)	0.1
12	69.0	(144, 5)	31.5	(144, 2)	0.0	(0, 0)	4.7	(144)	0.2
13	83.9	(100,21)	35.7	(100, 7)	0.0	(0, 0)	5.0	(100)	0.3
14	94.9	(19,10)	49.0	(359, 2)	0.0	(0, 0)	7.6	(286)	0.3
15	85.4	(31,19)	49.9	(31, 8)	0.0	(0, 0)	13.4	(31)	0.3
16	90.9	(310,24)	39.8	(24, 6)	0.0	(0, 0)	12.5	(24)	0.2
17	72.5	(19,19)	32.2	(287, 6)	0.0	(0, 0)	6.4	(24)	0.3
18	65.4	(82,23)	25.5	(319, 3)	0.0	(0, 0)	4.7	(319)	0.2
19	55.6	(363, 7)	18.5	(363, 3)	0.0	(0, 0)	3.3	(329)	0.1
20	49.8	(24,22)	18.7	(316, 2)	0.0	(0, 0)	5.1	(319)	0.1
21	82.5	(110, 4)	43.7	(110, 2)	0.0	(0, 0)	7.6	(118)	0.2
22	55.1	(14,11)	39.4	(307, 1)	0.0	(0, 0)	5.1	(307)	0.1
23	57.8	(230, 2)	36.1	(365, 5)	0.0	(0, 0)	7.1	(365)	0.4
24	69.5	(144, 5)	34.4	(144, 2)	0.0	(0, 0)	5.1	(144)	0.3
25	75.7	(109,21)	41.0	(100, 7)	0.0	(0, 0)	7.0	(253)	0.4
26	107.9	(359, 5)	90.8	(359, 2)	0.0	(0, 0)	11.3	(359)	0.4
27	95.5	(31,24)	42.7	(24, 4)	0.0	(0, 0)	11.3	(24)	0.3
28	79.9	(19,19)	38.6	(207, 6)	0.0	(0, 0)	8.7	(24)	0.3
29	83.5	(12, 4)	38.1	(119, 0)	0.0	(0, 0)	6.8	(119)	0.3
30	63.5	(363, 6)	31.9	(12, 1)	0.0	(0, 0)	4.6	(319)	0.2
31	74.9	(110, 4)	39.2	(363, 4)	0.0	(0, 0)	11.1	(118)	0.2
32	62.9	(14,11)	34.6	(307, 1)	0.0	(0, 0)	4.5	(307)	0.2
33	80.4	(306, 9)	26.8	(306, 3)	0.0	(0, 0)	9.2	(306)	0.2
34	53.1	(313,10)	32.3	(343, 6)	0.0	(0, 0)	6.0	(80)	0.5
35	78.6	(70, 8)	47.2	(365, 5)	0.0	(0, 0)	10.7	(365)	0.6
36	92.3	(359, 3)	61.6	(300, 7)	0.0	(0, 0)	10.7	(300)	0.5
37	68.1	(358, 4)	45.4	(100, 7)	0.0	(0, 0)	9.9	(253)	0.5
38	127.6	(359, 9)	55.3	(11, 8)	0.0	(0, 0)	12.2	(358)	0.5
39	90.7	(24,19)	47.3	(338, 7)	0.0	(0, 0)	12.4	(24)	0.4
40	91.9	(68,14)	33.3	(329, 1)	0.0	(0, 0)	7.2	(329)	0.2
41	97.3	(363,10)	51.2	(363, 4)	0.0	(0, 0)	16.1	(118)	0.3
42	72.6	(307, 1)	34.1	(22, 2)	0.0	(0, 0)	7.1	(22)	0.3
43	67.3	(306, 9)	32.1	(306, 6)	0.0	(0, 0)	14.3	(306)	0.3
44	95.5	(306,23)	29.5	(306, 8)	0.0	(0, 0)	7.2	(306)	0.3
45	102.6	(40,19)	55.0	(357, 8)	0.0	(0, 0)	10.9	(357)	0.6
46	102.0	(359, 1)	81.5	(358, 1)	0.0	(0, 0)	13.2	(23)	0.9
47	79.5	(343,10)	51.3	(343, 6)	0.0	(0, 0)	9.7	(80)	1.0
48	86.0	(359, 5)	42.9	(332, 7)	0.0	(0, 0)	10.4	(02)	1.0
49	97.0	(82,17)	47.6	(286, 6)	0.0	(0, 0)	10.2	(338)	0.8
50	109.0	(297,17)	60.9	(332, 3)	0.0	(0, 0)	17.5	(24)	0.6

PROJECT: KI SAWYER AFB   POLLUTANT: SO2   CONCENTRATION UNITS: UG/M**3

MAXIMUM CONCENTRATIONS AT EACH RECEPTOR

#	1-HOUR		3-HOUR		8-HOUR		24-HOUR		ANNUAL
51	102.0	(316, 6)	51.9	(316, 2)	0.0	(0, 0)	18.9	(118)	0.5
52	147.5	(306, 9)	53.8	(22, 2)	0.0	(0, 0)	18.6	(306)	0.6
53	68.0	(36,18)	32.4	(364, 1)	0.0	(0, 0)	11.0	(364)	0.5
54	91.3	(97,23)	50.0	(97, 8)	0.0	(0, 0)	9.3	(307)	0.4
55	89.1	(14,18)	32.0	(14, 6)	0.0	(0, 0)	7.6	(308)	0.3
56	87.9	(101, 7)	42.9	(33, 7)	0.0	(0, 0)	11.2	(360)	0.6
57	100.6	(33,19)	57.9	(33, 7)	0.0	(0, 0)	13.5	(360)	0.7
58	104.0	(33,19)	52.1	(12, 6)	0.0	(0, 0)	14.8	(360)	0.9
59	126.8	(358, 6)	67.9	(6, 2)	0.0	(0, 0)	19.6	(49)	1.4
60	139.2	(23,13)	101.6	(23, 5)	0.0	(0, 0)	25.7	(23)	2.7
61	125.7	(79,11)	54.7	(201, 4)	0.0	(0, 0)	12.9	(218)	0.4
62	123.5	(364, 8)	106.4	(364, 1)	0.0	(0, 0)	33.4	(364)	1.5
63	95.6	(307,17)	81.7	(8, 6)	0.0	(0, 0)	19.8	(308)	1.2
64	93.6	(97,20)	41.9	(97, 7)	0.0	(0, 0)	11.6	(83)	0.8
65	82.6	(97,20)	43.6	(20, 7)	0.0	(0, 0)	7.8	(83)	0.6
66	72.5	(20,19)	49.9	(20, 7)	0.0	(0, 0)	7.7	(116)	0.5
67	88.3	(90,24)	29.6	(88, 1)	0.0	(0, 0)	7.1	(360)	0.6
68	115.8	(12,10)	45.2	(12, 4)	0.0	(0, 0)	9.5	(39)	0.7
69	113.5	(57, 9)	43.0	(333, 2)	0.0	(0, 0)	12.9	(32)	1.0
70	95.7	(88,12)	59.8	(51, 7)	0.0	(0, 0)	19.7	(38)	1.3
71	124.6	(29, 1)	77.3	(15, 8)	0.0	(0, 0)	25.8	(10)	1.8
72	152.5	(16,12)	75.7	(35, 2)	0.0	(0, 0)	25.4	(248)	1.6
73	128.6	(19,10)	113.5	(29, 3)	0.0	(0, 0)	46.7	(48)	3.2
74	99.6	(5,13)	63.9	(347, 4)	0.0	(0, 0)	30.4	(347)	2.5
75	109.1	(5,21)	61.4	(46, 1)	0.0	(0, 0)	17.0	(66)	1.4
76	74.2	(5,21)	49.1	(364, 6)	0.0	(0, 0)	12.6	(66)	1.0
77	104.4	(5,18)	62.7	(5, 7)	0.0	(0, 0)	12.3	(5)	0.8
78	59.9	(70, 1)	46.7	(136, 8)	0.0	(0, 0)	6.4	(136)	0.4
79	97.6	(337, 6)	34.1	(136, 7)	0.0	(0, 0)	7.7	(23)	0.5
80	75.5	(138,21)	40.9	(355, 2)	0.0	(0, 0)	8.8	(340)	0.7
81	94.5	(5, 5)	54.9	(29, 8)	0.0	(0, 0)	16.7	(77)	1.1
82	102.2	(16,13)	80.1	(27, 1)	0.0	(0, 0)	23.7	(40)	1.5
83	108.1	(4,14)	67.6	(25, 7)	0.0	(0, 0)	18.3	(25)	1.3
84	124.8	(53, 8)	67.3	(19, 5)	0.0	(0, 0)	10.9	(60)	1.0
85	117.8	(354,10)	65.3	(8, 3)	0.0	(0, 0)	22.6	(1)	1.5
86	105.3	(4,16)	50.1	(45, 8)	0.0	(0, 0)	17.5	(48)	1.3
87	110.9	(7,20)	53.1	(7, 7)	0.0	(0, 0)	14.5	(336)	1.2
88	95.9	(336,17)	70.1	(336, 6)	0.0	(0, 0)	13.6	(336)	1.1
89	88.9	(70, 4)	30.4	(355, 2)	0.0	(0, 0)	4.9	(340)	0.4
90	78.8	(59, 5)	37.8	(59, 2)	0.0	(0, 0)	6.6	(10)	0.5
91	100.3	(69, 7)	44.1	(265, 8)	0.0	(0, 0)	9.3	(265)	0.7
92	99.4	(69, 8)	56.5	(28, 1)	0.0	(0, 0)	14.6	(27)	1.0
93	105.3	(74, 9)	64.4	(343, 1)	0.0	(0, 0)	25.4	(343)	1.2
94	88.5	(55, 9)	46.2	(56, 3)	0.0	(0, 0)	10.9	(25)	0.9
95	91.9	(111, 6)	44.7	(220, 7)	0.0	(0, 0)	7.3	(276)	0.6
96	108.2	(45, 9)	47.0	(13, 6)	0.0	(0, 0)	8.4	(353)	0.7
97	75.2	(306, 6)	56.1	(7, 8)	0.0	(0, 0)	18.2	(7)	0.9
98	105.5	(318, 9)	35.2	(314, 3)	0.0	(0, 0)	12.3	(31)	1.0
99	88.7	(52,21)	43.7	(45, 8)	0.0	(0, 0)	9.8	(48)	0.8
100	81.4	(301, 1)	27.1	(301, 1)	0.0	(0, 0)	4.8	(77)	0.4

PROJECT: KI SAWYER AFB   POLLUTANT: SO2   CONCENTRATION UNITS: UG/M**3

MAXIMUM CONCENTRATIONS AT EACH RECEPTOR

#	1-HOUR		3-HOUR		0-HOUR		24-HOUR		ANNUAL
101	98.8	(69, 7)	36.2	(69, 3)	0.0	(0, 0)	7.0	(359)	0.5
102	91.4	(320,24)	43.6	(341, 1)	0.0	(0, 0)	8.6	(27)	0.6
103	86.7	(278,21)	43.2	(335, 6)	0.0	(0, 0)	12.9	(13)	0.7
104	104.1	(46, 9)	44.5	(40, 2)	0.0	(0, 0)	9.3	(343)	0.9
105	103.9	(55, 9)	34.6	(55, 3)	0.0	(0, 0)	7.2	(25)	0.7
106	93.6	(147, 8)	45.3	(335, 7)	0.0	(0, 0)	6.9	(25)	0.5
107	82.1	(312, 8)	49.0	(291, 3)	0.0	(0, 0)	9.8	(291)	0.5
108	84.5	(45, 9)	44.0	(18, 6)	0.0	(0, 0)	8.0	(353)	0.5
109	93.1	(7, 2)	47.3	(7, 8)	0.0	(0, 0)	16.3	(7)	0.7
110	92.5	(71, 8)	58.3	(306, 2)	0.0	(0, 0)	11.7	(306)	0.8
111	83.3	(69, 7)	29.5	(69, 3)	0.0	(0, 0)	5.5	(359)	0.4
112	97.8	(12,10)	41.1	(12, 7)	0.0	(0, 0)	5.8	(77)	0.4
113	106.1	(13,10)	35.4	(13, 4)	0.0	(0, 0)	9.8	(13)	0.5
114	85.7	(61, 6)	46.3	(152, 1)	0.0	(0, 0)	9.8	(343)	0.6
115	79.4	(49, 1)	39.9	(36, 4)	0.0	(0, 0)	9.1	(292)	0.7
116	101.2	(55, 9)	33.7	(55, 3)	0.0	(0, 0)	5.7	(292)	0.5
117	114.0	(4,20)	55.0	(4, 7)	0.0	(0, 0)	11.3	(4)	0.5
118	81.8	(291, 8)	27.4	(291, 3)	0.0	(0, 0)	3.7	(25)	0.4
119	84.4	(312, 9)	54.0	(294, 1)	0.0	(0, 0)	7.3	(294)	0.4
120	94.7	(18,18)	46.5	(18, 6)	0.0	(0, 0)	6.1	(353)	0.4
121	94.9	(34, 9)	34.8	(7, 8)	0.0	(0, 0)	13.7	(7)	0.5

PROJECT: KI SAWYER AFB POLLUTANT: SO2 CONCENTRATION UNITS: UG/M**3

MAXIMUM DAILY CONCENTRATIONS

DAY	24-HOUR CONCENTRATION	RECEPTOR
48	46.7	73
43	35.4	73
364	33.4	62
347	30.4	74
309	28.7	62
31	27.8	73
345	27.8	73
60	27.6	73
29	26.7	73
10	25.8	71
23	25.7	60
71	25.6	73
343	25.4	93
248	25.4	72
307	25.2	62
263	24.9	62
53	24.2	73
40	23.7	82
30	23.5	73
341	23.0	73
1	22.6	85
63	22.4	60
35	22.1	72
8	22.0	85
330	21.5	73
112	21.4	62
50	20.7	60
42	20.3	73
17	20.0	74
27	20.0	82
134	19.9	60
38	19.7	70
49	19.6	59
281	19.6	62
45	19.2	73
102	19.0	73
119	18.9	51
306	18.6	52
25	18.3	83
6	18.3	59
7	18.2	97
339	18.2	49
124	18.1	62
352	18.0	72
105	17.7	60
11	17.6	60
336	17.6	74
24	17.5	50
331	17.5	71
361	17.3	82

PROJECT: KI SAWYER AFB   POLLUTANT: SO2   CONCENTRATION UNITS: UG/M**3

MAXIMUM 3-HOUR CONCENTRATIONS

DAY	3-HOUR CONCENTRATION	RECEPTOR	TIME PERIOD
29	113.5	73	3
364	106.4	62	1
23	101.6	60	5
85	99.5	60	6
43	99.0	73	2
74	92.8	73	1
315	91.1	60	2
359	90.8	26	2
1	89.5	73	6
345	89.1	73	3
48	88.7	73	4
308	84.0	62	3
42	83.7	73	7
364	83.2	62	2
43	82.1	73	4
8	81.7	63	6
358	81.5	46	1
27	80.1	82	1
364	77.7	62	3
15	77.3	71	8
60	77.1	73	3
120	76.7	60	2
35	75.7	72	2
340	75.4	60	2
331	75.1	71	5
60	74.9	73	3
31	74.8	73	1
345	74.5	73	1
19	74.2	73	4
240	73.8	72	6
92	73.5	73	4
82	73.2	60	3
46	73.2	60	6
163	71.9	62	5
359	70.7	71	7
336	70.1	88	6
22	70.0	62	3
78	70.0	60	6
29	69.8	73	2
45	69.8	73	5
4	69.6	46	8
40	69.6	82	4
49	69.3	60	6
239	69.2	72	3
350	68.4	62	6
341	68.0	73	6
6	67.9	59	2
25	67.6	83	7
281	67.4	62	7
19	67.3	84	5

PRINTOUT FROM
CRSTER MODEL RUN FOR
MODIFIED HEATING PLANT
(BOILERS #5 AND #6 AND NEW BOILERS
AT FULL LOAD BURNING 0.98% SULFUR)

For purposes of this model run, existing boilers 5 and 6 were treated as one emission point. The emission rate used was the sum of emissions from the two boilers while the flow rate was the average of the two boilers.

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PLANT NAME: KI SAWYER AFB              POLLUTANT: SO2        AIR QUALITY UNITS: UG/M**3
*** SCENARIO ONE    *** ALL DAYS *** 121 RECEPTORS *** 1 KM GRID SPACING ***

              MET FILE       REQUESTED
             STN NO. YR    STN NO. YR
 SURFACE      94836  64     94836  64
 UPPER AIR    14847  64     14847  64
PLANT LOCATION: RURAL
NO TAPE OUTPUT
MET DATA WILL NOT BE PRINTED

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     ALL TABLES, INCLUDING SOURCE CONTRIBUTION, THAT CONTAIN "ANNUAL" IN THE HEADING ARE BASED ONLY ON THOSE DAYS

     MARKED BY "I" IN THE ABOVE TABLE
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ST	IDENT	MONTH	U T M EAST	NORTH	EMISSIONS (TONS/DAY)	HEIGHT (FEET)	DIAMETER (FEET)	VELOCITY (FT/SEC)	TEMP (DEG.F)	FLOW RATE (FT**3/SEC)	ELEV (FEET)
1	STACK NO. 1	ALL	470.4	5131.0	1.1800	82.0	4.3	17.5	360.	254.1	0.0
2	STACK NO. 2	ALL	470.4	5131.0	1.0800	80.0	4.3	27.8	350.	403.7	0.0

PROJECT: KI SAWYER AFB   POLLUTANT: SO2   CONCENTRATION UNITS: UG/M**3

MAXIMUM CONCENTRATIONS AT EACH RECEPTOR

#	1-HOUR	3-HOUR	0-HOUR	24-HOUR	ANNUAL
MAX	369.6 (165. 7)	181.6 (182. 4)	0.0 (0. 0)	70.8 (263)	6.1
RCP	72	72	121	62	73
1	133.8 (100.21)	80.9 (218. 7)	0.0 (0. 0)	10.9 (253)	0.5
2	134.3 (100.20)	61.0 (52. 7)	0.0 (0. 0)	9.1 (196)	0.6
3	153.4 (144. 2)	69.2 (359. 2)	0.0 (0. 0)	17.2 (286)	0.5
4	136.2 (259.20)	60.1 (228. 3)	0.0 (0. 0)	14.0 (31)	0.5
5	127.1 (318.23)	57.8 (318. 8)	0.0 (0. 0)	12.4 (24)	0.3
6	144.3 (150.22)	57.4 (150. 8)	0.0 (0. 0)	11.6 (150)	0.4
7	122.9 (259.21)	41.0 (259. 7)	0.0 (0. 0)	6.7 (121)	0.3
8	97.9 (146.22)	32.6 (146. 8)	0.0 (0. 0)	9.2 (123)	0.3
9	124.1 (194.22)	41.4 (194. 8)	0.0 (0. 0)	9.4 (194)	0.3
10	79.3 (124.21)	32.3 (314. 4)	0.0 (0. 0)	8.2 (319)	0.3
11	131.2 (110. 4)	81.7 (110. 2)	0.0 (0. 0)	11.7 (118)	0.3
12	150.6 (144. 5)	74.7 (144. 2)	0.0 (0. 0)	14.1 (235)	0.6
13	147.7 (100.21)	76.2 (218. 7)	0.0 (0. 0)	13.6 (253)	0.6
14	157.1 (286.19)	61.0 (233. 7)	0.0 (0. 0)	15.2 (286)	0.7
15	163.1 (227.21)	77.5 (31. 8)	0.0 (0. 0)	20.5 (31)	0.6
16	132.5 (318.24)	62.1 (318. 8)	0.0 (0. 0)	17.1 (24)	0.4
17	157.4 (150.22)	66.5 (287. 6)	0.0 (0. 0)	12.9 (150)	0.5
18	167.1 (249.20)	67.3 (168. 8)	0.0 (0. 0)	8.8 (319)	0.4
19	161.8 (153.21)	53.9 (153. 7)	0.0 (0. 0)	8.9 (123)	0.3
20	79.1 (208. 3)	34.7 (316. 2)	0.0 (0. 0)	9.3 (319)	0.3
21	145.5 (110. 4)	77.1 (110. 2)	0.0 (0. 0)	16.1 (118)	0.3
22	94.0 (306.24)	69.3 (307. 1)	0.0 (0. 0)	9.1 (307)	0.3
23	172.8 (144. 6)	57.7 (144. 2)	0.0 (0. 0)	11.5 (265)	0.9
24	136.5 (144. 5)	78.4 (144. 2)	0.0 (0. 0)	19.0 (235)	0.8
25	138.3 (210.20)	72.9 (100. 7)	0.0 (0. 0)	17.3 (235)	0.9
26	171.1 (286.23)	99.5 (359. 2)	0.0 (0. 0)	18.6 (286)	0.8
27	141.5 (31.24)	62.8 (328. 8)	0.0 (0. 0)	15.8 (235)	0.6
28	161.0 (150.22)	76.5 (287. 6)	0.0 (0. 0)	13.9 (150)	0.6
29	146.2 (146.22)	81.4 (123. 7)	0.0 (0. 0)	13.0 (146)	0.6
30	115.5 (173. 4)	63.3 (263. 2)	0.0 (0. 0)	11.0 (263)	0.4
31	124.9 (110. 4)	66.7 (144. 4)	0.0 (0. 0)	23.2 (118)	0.5
32	103.5 (307. 1)	58.9 (307. 1)	0.0 (0. 0)	8.2 (319)	0.4
33	128.7 (222.21)	42.9 (222. 7)	0.0 (0. 0)	12.8 (306)	0.4
34	151.0 (261.21)	62.2 (203. 8)	0.0 (0. 0)	12.8 (194)	1.2
35	138.9 (229.22)	73.0 (229. 7)	0.0 (0. 0)	21.3 (265)	1.3
36	139.7 (144. 6)	107.6 (300. 7)	0.0 (0. 0)	25.0 (235)	1.3
37	179.4 (210. 6)	92.0 (186. 7)	0.0 (0. 0)	24.5 (235)	1.3
38	214.7 (358. 9)	83.7 (358. 3)	0.0 (0. 0)	16.7 (358)	1.0
39	146.8 (183. 7)	83.3 (287. 6)	0.0 (0. 0)	17.6 (24)	0.8
40	134.5 (153.21)	64.3 (121. 5)	0.0 (0. 0)	16.9 (123)	0.5
41	146.7 (363.10)	86.0 (363. 4)	0.0 (0. 0)	33.2 (118)	0.7
42	116.0 (307. 1)	46.2 (22. 2)	0.0 (0. 0)	10.8 (119)	0.5
43	167.1 (177.22)	61.2 (306. 6)	0.0 (0. 0)	22.5 (306)	0.7
44	144.8 (306.23)	48.3 (306. 8)	0.0 (0. 0)	12.1 (306)	0.6
45	159.7 (208.21)	100.3 (211. 8)	0.0 (0. 0)	23.1 (252)	1.4
46	223.2 (209. 6)	123.7 (209. 2)	0.0 (0. 0)	30.3 (209)	1.9
47	160.7 (261.21)	81.3 (343. 6)	0.0 (0. 0)	21.1 (194)	2.2
48	162.1 (144. 6)	79.9 (332. 7)	0.0 (0. 0)	20.0 (235)	2.3
49	182.4 (190.20)	106.4 (227. 5)	0.0 (0. 0)	29.0 (338)	1.9
50	185.9 (287.17)	107.8 (233. 3)	0.0 (0. 0)	26.3 (24)	1.1

PROJECT: KI SAWYER AFB   POLLUTANT: SO2   CONCENTRATION UNITS: UG/M**3

MAXIMUM CONCENTRATIONS AT EACH RECEPTOR

#	1-HOUR		3-HOUR		0-HOUR		24-HOUR		ANNUAL
51	179.2	(189,18)	131.4	(263, 1)	0.0	(0, 0)	37.1	(118)	1.0
52	153.0	(306, 9)	74.0	(22, 2)	0.0	(0, 0)	26.9	(122)	1.1
53	114.9	(215,23)	57.6	(123, 5)	0.0	(0, 0)	18.3	(364)	1.1
54	170.4	(97,23)	88.8	(97, 8)	0.0	(0, 0)	17.8	(307)	1.0
55	127.2	(14,18)	55.4	(266, 8)	0.0	(0, 0)	14.9	(308)	0.8
56	174.9	(101, 7)	65.4	(33, 7)	0.0	(0, 0)	18.0	(360)	1.3
57	151.0	(33,19)	89.3	(33, 7)	0.0	(0, 0)	21.5	(360)	1.5
58	181.8	(303, 8)	82.3	(268, 7)	0.0	(0, 0)	23.3	(360)	1.9
59	148.2	(252,15)	115.1	(98, 4)	0.0	(0, 0)	29.3	(296)	2.9
60	225.2	(191,20)	157.2	(315, 2)	0.0	(0, 0)	54.3	(195)	5.7
61	268.6	(201,13)	112.9	(201, 4)	0.0	(0, 0)	25.4	(201)	0.5
62	214.1	(124, 8)	169.9	(364, 1)	0.0	(0, 0)	70.8	(263)	3.1
63	166.1	(215, 7)	116.9	(190, 2)	0.0	(0, 0)	37.0	(308)	2.8
64	163.4	(97,20)	75.9	(97, 7)	0.0	(0, 0)	20.6	(125)	2.0
65	153.0	(97,20)	68.4	(189, 2)	0.0	(0, 0)	15.1	(107)	1.5
66	121.1	(119,22)	84.9	(116, 8)	0.0	(0, 0)	15.0	(116)	1.3
67	162.0	(244,20)	67.9	(244, 7)	0.0	(0, 0)	11.5	(244)	1.1
68	168.6	(12,10)	80.5	(222, 3)	0.0	(0, 0)	14.0	(244)	1.4
69	172.7	(57, 9)	67.3	(244, 7)	0.0	(0, 0)	21.2	(225)	1.9
70	149.8	(296, 2)	111.4	(244, 3)	0.0	(0, 0)	33.1	(295)	2.5
71	216.0	(140,12)	139.8	(176, 1)	0.0	(0, 0)	36.8	(10)	3.3
72	369.6	(165, 7)	181.6	(182, 4)	0.0	(0, 0)	50.9	(248)	2.7
73	272.2	(219, 6)	163.5	(29, 3)	0.0	(0, 0)	70.0	(48)	6.1
74	161.7	(206,22)	105.1	(347, 4)	0.0	(0, 0)	49.4	(347)	5.2
75	165.2	(5,21)	97.1	(46, 1)	0.0	(0, 0)	29.3	(170)	3.2
76	114.6	(188, 3)	73.3	(364, 6)	0.0	(0, 0)	22.4	(246)	2.3
77	151.8	(131,21)	96.0	(5, 7)	0.0	(0, 0)	18.4	(5)	1.7
78	124.2	(137, 6)	92.9	(136, 8)	0.0	(0, 0)	13.1	(136)	0.9
79	169.2	(136,20)	75.3	(136, 7)	0.0	(0, 0)	11.6	(108)	1.0
80	173.3	(193, 1)	61.8	(355, 2)	0.0	(0, 0)	16.7	(225)	1.3
81	152.6	(230, 5)	91.8	(310, 4)	0.0	(0, 0)	26.3	(77)	2.0
82	168.9	(266, 9)	112.1	(27, 1)	0.0	(0, 0)	35.7	(40)	2.7
83	198.7	(165, 7)	125.5	(248, 6)	0.0	(0, 0)	44.8	(248)	2.5
84	183.2	(53, 8)	99.0	(19, 5)	0.0	(0, 0)	19.2	(175)	2.1
85	154.8	(145, 7)	94.3	(8, 3)	0.0	(0, 0)	31.2	(8)	2.9
86	189.8	(182, 6)	90.5	(207, 8)	0.0	(0, 0)	25.7	(48)	2.8
87	160.8	(7,20)	75.7	(7, 7)	0.0	(0, 0)	26.4	(289)	2.5
88	155.9	(336,17)	112.9	(336, 6)	0.0	(0, 0)	22.0	(336)	2.3
89	178.2	(141, 6)	59.4	(141, 2)	0.0	(0, 0)	9.8	(225)	0.8
90	165.3	(146, 6)	82.4	(183, 8)	0.0	(0, 0)	11.9	(255)	1.1
91	157.2	(69, 7)	88.4	(265, 8)	0.0	(0, 0)	18.7	(265)	1.4
92	169.7	(132, 7)	96.7	(204, 1)	0.0	(0, 0)	22.8	(204)	1.8
93	166.9	(74, 9)	104.9	(343, 1)	0.0	(0, 0)	40.9	(343)	2.1
94	137.9	(55, 9)	72.1	(248, 6)	0.0	(0, 0)	26.9	(248)	1.8
95	151.9	(236,21)	77.6	(228, 7)	0.0	(0, 0)	16.6	(276)	1.3
96	168.7	(132,23)	70.0	(201, 7)	0.0	(0, 0)	19.7	(143)	1.5
97	124.2	(154, 6)	81.0	(7, 8)	0.0	(0, 0)	26.4	(7)	1.8
98	195.8	(129, 6)	65.3	(129, 2)	0.0	(0, 0)	17.1	(31)	2.0
99	145.0	(207,23)	90.3	(207, 8)	0.0	(0, 0)	15.0	(288)	1.6
100	150.1	(301, 1)	50.0	(301, 1)	0.0	(0, 0)	8.9	(255)	0.8

PROJECT: KI SAWYER AFB POLLUTANT: SO2 CONCENTRATION UNITS: UG/M**3

MAXIMUM CONCENTRATIONS AT EACH RECEPTOR

#	1-HOUR		3-HOUR		0-HOUR		24-HOUR		ANNUAL
101	155.1	(69, 7)	80.3	(265, 8)	0.0	(0, 0)	17.0	(265)	1.0
102	147.3	(221, 2)	66.4	(341, 1)	0.0	(0, 0)	16.8	(204)	1.2
103	170.2	(278,21)	70.8	(335, 6)	0.0	(0, 0)	20.6	(226)	1.3
104	175.2	(203, 7)	67.9	(325, 8)	0.0	(0, 0)	17.6	(292)	1.7
105	157.7	(55, 9)	74.6	(55, 3)	0.0	(0, 0)	18.2	(248)	1.4
106	147.5	(163, 6)	73.1	(335, 7)	0.0	(0, 0)	15.3	(238)	1.1
107	152.7	(312, 8)	71.0	(291, 3)	0.0	(0, 0)	15.4	(291)	1.1
108	171.3	(262, 8)	78.4	(262, 3)	0.0	(0, 0)	13.3	(353)	1.1
109	147.8	(133, 2)	67.0	(7, 8)	0.0	(0, 0)	23.4	(7)	1.3
110	152.7	(202,24)	100.0	(306, 2)	0.0	(0, 0)	20.3	(306)	1.6
111	149.4	(222, 6)	66.6	(265, 8)	0.0	(0, 0)	14.1	(265)	0.8
112	147.2	(12,19)	66.7	(259, 2)	0.0	(0, 0)	10.4	(204)	0.9
113	148.9	(13,10)	49.7	(13, 4)	0.0	(0, 0)	13.9	(13)	1.0
114	156.6	(212, 7)	90.5	(152, 1)	0.0	(0, 0)	16.9	(152)	1.2
115	146.2	(139, 6)	91.0	(216, 8)	0.0	(0, 0)	19.6	(292)	1.3
116	151.8	(55, 9)	76.3	(55, 3)	0.0	(0, 0)	13.5	(248)	1.1
117	164.0	(4,20)	81.2	(4, 7)	0.0	(0, 0)	16.9	(4)	1.0
118	134.3	(236,21)	75.3	(236, 7)	0.0	(0, 0)	9.4	(236)	0.8
119	213.9	(216, 7)	103.6	(294, 1)	0.0	(0, 0)	14.0	(294)	0.9
120	133.8	(18,18)	65.1	(18, 6)	0.0	(0, 0)	10.1	(353)	0.8
121	144.7	(34, 9)	58.8	(312, 8)	0.0	(0, 0)	19.4	(7)	1.0

PROJECT: KI SAWYER AFB   POLLUTANT: SO2   CONCENTRATION UNITS: UG/M**3

MAXIMUM DAILY CONCENTRATIONS

DAY	24-HOUR CONCENTRATION	RECEPTOR
263	70.8	62
48	70.0	73
195	54.3	60
43	53.4	73
134	53.2	60
364	53.0	62
248	50.9	72
214	50.0	73
347	49.4	74
308	48.3	62
194	47.7	60
170	46.8	74
345	45.4	73
31	44.0	73
23	43.7	60
124	43.6	62
281	41.5	62
112	41.3	62
60	41.0	73
343	40.9	93
219	40.7	73
307	40.5	62
71	40.2	73
330	38.5	73
133	38.5	60
239	38.4	72
29	38.1	73
118	37.1	51
341	37.0	73
157	36.8	73
10	36.8	71
186	36.6	60
231	36.3	60
102	36.0	73
223	36.0	73
53	35.9	73
164	35.9	74
40	35.7	82
63	35.1	60
167	34.9	60
161	34.8	73
125	34.2	62
35	34.1	72
295	33.1	70
30	33.0	73
123	32.8	62
264	32.7	63
274	32.6	62
196	32.3	60
289	32.3	73

PROJECT: KI SAWYER AFB POLLUTANT: SO2 CONCENTRATION UNITS: UG/M**3

MAXIMUM 3-HOUR CONCENTRATIONS

DAY	3-HOUR CONCENTRATION	RECEPTOR	TIME PERIOD
182	181.6	72	4
364	169.9	62	1
256	163.8	72	4
29	163.5	73	3
239	158.9	72	4
315	157.2	60	2
85	156.4	60	6
248	154.7	72	6
181	148.9	73	6
239	148.1	72	3
43	147.0	73	2
92	146.5	73	4
345	145.5	73	3
263	144.6	62	7
74	143.0	73	1
308	142.7	62	3
221	142.3	60	6
281	141.2	62	7
191	141.0	60	7
176	139.8	71	1
120	139.1	60	2
331	138.9	71	5
23	138.8	60	5
134	133.1	60	1
48	131.5	73	4
263	131.4	51	1
364	131.3	62	2
263	131.1	62	6
263	130.2	62	5
251	129.9	73	6
107	129.2	62	4
263	128.4	62	8
189	128.1	73	1
1	126.9	73	6
167	126.6	60	7
124	126.5	62	3
195	125.8	60	3
248	125.5	83	6
174	125.4	62	5
294	124.9	62	8
312	124.4	73	5
209	123.7	46	2
42	123.5	73	7
165	123.2	72	3
220	122.8	71	7
364	122.7	62	3
94	122.6	60	3
43	122.4	73	4
345	122.3	73	1
207	121.3	71	3

APPENDIX E

CONTROL TECHNOLOGY REQUIREMENT

APPENDIX E

REVIEW OF CONTROL TECHNOLOGY

The rate of heat input for each of the new boilers is less than 250 million Btu per hour and therefore the New Source Performance Standards (NSPS) for fossil-fuel fired steam generators do not apply. However, the existing plant is a major source and for the scenarios under which net increase of any pollutant exceed the de minimus values for that pollutant, the boilers will be subject to PSD review. The de minimus values for various pollutants are given in Table 3.5. PSD regulations require that best available control technology be applied when emissions exceed the de minimus values. Under those scenarios that the boilers are not subject to PSD regulations, Michigan rules 220, 331, 370, and 402 will be applicable.

ALLOWABLE EMISSIONS

Boilers subject to BACT review may be required to meet the NSPS limits for fossil-fired steam generators. The NSPS limit for such boilers are:

TSP 0.1 lb/MMBtu
SO_2 1.2 lb/MMBtu

When PSD review is not required, the proposed boilers will be subject to rules 220, 331, 370, and 402 of the Michigan Air Pollution Control Regulations. Rule 331 limits particulate emissions to 0.1 lb per million Btu, whereas rule 402 limits the SO_2 emissions to no more than 2.4 lb per million Btu. Without considering PSD applicability, the allowable emissions (lb/hr) under NSPS and Michigan regulations will be as given below.

	NSPS		Michigan Regulations	
	Each Boiler	Total	Each Boiler	Total
TSP	7.0	14.0	7.0	14.0
SO_2	84.0	168.0	168.0	336.0

There are no limits for other pollutants.

Ash Content and Particulate Control Requirements

Particulate emissions from coal burning depend upon the ash content of the coal being used. EPA publication AP-42 gives an emission factor of 13 times the ash content for stoker boilers. Assuming a heating value of coal equal to 13,420 Btu/lb, it is estimated that each boiler will burn about 2.41 tons of coal per hour. A coal of such heating value would require an ash content of less than 0.20% to comply with the emission limits under NSPS and Michigan regulations. BACT analysis may require a more stringent level of TSP control. Particulate control equipment efficiencies to meet two possible levels of control (0.03 and 0.1 lb/MMBtu) are given below:

Ash Content	Required Particulate Control Efficiency to Meet Emission Limits of 0.1 lb/MMBtu	Required Particulate Control Efficiency to Meet Emission Limits of 0.03 lb/MMBtu
0.2%	none	69.2
5.0%	95.8	98.7
6.0%	96.5	98.9
8.0%	97.4	99.2
10.0%	97.9	99.3

Fugitive Particulates

Fugitive emissions are regulated under Michigan rule 371. This rule applies only to Priority I and II areas. The KI Sawyer AFB is not located in those areas. Coal and ash handling and storage, however, will be subject to this regulation. Two different techniques may be considered to control fugitive particulate matter: dry baghouse type collectors for the railroad unloading station, coal storage silos, and the coal bunkers, and a foam dust suppression system to control dust generated by the coal and ash discharge and conveying systems. With these kinds of control devices, emissions of fugitive particulates are expected to be minimal.

Sulfur Content and SO_2 Control Requirements

The emission factor for SO_2 is 38 times the sulfur content of coal. Again, using a heating value of 13,420 Btu/lb for coal, each boiler will burn about 2.41 tons of coal per hour. To meet the emission limit of 2.4 lb per million Btu for SO_2, the sulfur content cannot exceed 1.7%. Sulfur contents higher than this value would require SO_2 removal efficiencies as given below:

Sulfur Content	Required SO_2 Removal Efficiency to meet 2.4 lb/MMBtu
1.7%	none
2.0%	15.2%
2.5%	32.2%
3.0%	43.5%
3.5%	51.6%

If required to meet the NSPS limit of 1.2 lb/MMBtu, the sulfur content could not exceed 0.84%. Sulfur contents higher than this would require SO_2 removal efficiencies as given below:

Sulfur Content	Required SO_2 Removal Efficiency to meet 1.2 lb/MMBtu
0.84%	none
0.98%	13.5%
1.3%	34.8%
1.7%	50.0%
2.0%	57.6%
3.0%	71.7%

Michigan DNR considers 1.6 lb/MMBtu as BACT. This will require that the sulfur content of coal (with heating value of 13,420 Btu/lb) does not exceed 1.1%. The recommended sulfur content is 1.0% which is equivalent to 1.4 lb/MMBtu for coal with 13,420 Btu/lb.

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